2008

Financial Information

CANADIAN UTILITIES LIMITED
An ATCO Company

Consolidated Financial Statements

Management's Discussion and Analysis of Financial Condition and Results of Operations

For the Year Ended December 31, 2008

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MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

Management is responsible for the preparation of the consolidated financial statements, management's discussion and analysis of financial condition and results of operations and other financial information relating to the Corporation contained in this annual report. The consolidated financial statements have been prepared in conformity with Canadian generally accepted accounting principles using methods appropriate for the industries in which the Corporation operates and necessarily include some amounts that are based on informed judgments and best estimates of management. The financial information contained elsewhere in the annual report is consistent with that in the consolidated financial statements.

PricewaterhouseCoopers, our independent auditors, are engaged to express a professional opinion on the consolidated financial statements.

Management has established internal accounting and financial reporting control systems, which are subject to periodic review by the Corporation's internal auditors, to meet its responsibility for reliable and accurate reporting. Integral to these control systems are a code of ethics and management policies that provide guidance and direction to employees, as well as a system of corporate governance that provides oversight to the Corporation's operating, reporting and risk management activities.

The Board of Directors, through its Audit Committee comprised entirely of outside Directors, oversees management's responsibilities for financial reporting. The Audit Committee meets regularly with management, the internal auditors and the independent auditors to discuss auditing and reporting on financial matters, to assure that management is carrying out its responsibilities and to review and approve the consolidated financial statements. The auditors have full and free access to the Audit Committee and management.

N.C. South

N.C. Southern
Deputy Chair, President & Chief Executive Officer

KM Watson

K.M. Watson
Senior Vice President & Chief Financial Officer

AUDITORS' REPORT

TO THE SHARE OWNERS OF CANADIAN UTILITIES LIMITED

We have audited the consolidated balance sheets of Canadian Utilities Limited as at December 31, 2008 and 2007 and the consolidated statements of earnings and retained earnings, cash flows and comprehensive income for each of the years in the two year period ended December 31, 2008. These consolidated financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the company as at December 31, 2008 and 2007 and the results of its operations and its cash flows for each of the years in the two year period ended December 31, 2008 in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta
February 17, 2009

Canadian Utilities Limited
Consolidated Statement of Earnings and Retained Earnings

(Millions of Canadian Dollars except per share data)

	Note	Three Months Ended December 31		Year Ended December 31	
		2008	2007	**2008**	2007
		(Unaudited)			
Revenues	3	**$ 744.3**	$ 657.1	**$2,778.9**	$2,404.9
Costs and expenses					
Natural gas supply		**3.6**	24.8	**37.9**	42.1
Purchased power		**14.9**	13.6	**54.1**	49.9
Operation and maintenance		**300.4**	251.4	**1,123.5**	941.6
Selling and administrative		**87.2**	77.1	**244.8**	216.8
Depreciation and amortization		**100.5**	99.0	**389.1**	351.5
Interest	6, 11	**60.3**	55.0	**233.5**	217.4
Franchise fees		**42.5**	37.4	**175.2**	151.2
		609.4	558.3	**2,258.1**	1,970.5
		134.9	98.8	**520.8**	434.4
Interest and other income	5	**14.6**	21.3	**59.1**	64.3
Earnings before income taxes		**149.5**	120.1	**579.9**	498.7
Income taxes	3, 6	**27.1**	13.1	**134.3**	77.7
		122.4	107.0	**445.6**	421.0
Dividends on equity preferred shares		**8.2**	8.3	**32.5**	34.3
Earnings attributable to Class A and Class B shares		**114.2**	98.7	**413.1**	386.7
Retained earnings at beginning of period		**2,209.8**	1,984.1	**2,036.0**	1,813.3
		2,324.0	2,082.8	**2,449.1**	2,200.0
Dividends on Class A and Class B shares		**41.7**	39.6	**166.8**	156.8
Purchase of Class A shares		**-**	7.2	**-**	7.2
Retained earnings at end of period		**$2,282.3**	$2,036.0	**$2,282.3**	$2,036.0
Earnings per Class A and Class B share	14	**$ 0.91**	$ 0.78	**$ 3.29**	$ 3.08
Diluted earnings per Class A and Class B share	14	**$ 0.91**	$ 0.78	**$ 3.28**	$ 3.07
Dividends paid per Class A and Class B share	14	**$ 0.3325**	$ 0.315	**$ 1.33**	$ 1.25

Canadian Utilities Limited
Consolidated Balance Sheet

(Millions of Canadian Dollars)

	Note	December 31 2008	2007
ASSETS			
Current assets			
Cash and short term investments	18	**$ 748.6**	$ 747.2
Accounts receivable		**385.5**	373.9
Inventories	7	**109.3**	101.8
Future income taxes	3, 6	**5.9**	-
Regulatory assets	2	**55.8**	30.0
Derivative assets	21	**1.7**	0.8
Prepaid expenses		**28.3**	29.8
		1,335.1	1,283.5
Property, plant and equipment	8	**6,208.5**	5,678.5
Regulatory assets	2	**65.3**	75.6
Derivative assets	21	**60.4**	73.3
Other assets	9	**195.1**	194.3
		$7,864.4	$7,305.2
LIABILITIES AND SHARE OWNERS' EQUITY			
Current liabilities			
Bank indebtedness	10	**$ 22.0**	$ -
Accounts payable and accrued liabilities		**479.5**	388.9
Income taxes payable	3, 6	**4.9**	1.2
Future income taxes	6	**-**	1.7
Regulatory liabilities	2	**29.3**	5.9
Derivative liabilities	21	**5.4**	2.6
Long term debt due within one year	11	**17.7**	-
Non-recourse long term debt due within one year	11	**44.8**	65.4
		603.6	465.7
Future income taxes	3, 6	**164.5**	153.8
Regulatory liabilities	2	**148.6**	146.5
Derivative liabilities	21	**12.4**	3.3
Deferred credits	12	**301.9**	307.9
Long term debt	11	**2,844.3**	2,603.2
Non-recourse long term debt	11	**412.4**	478.1
Equity preferred shares	13	**625.0**	625.0
Class A and Class B share owners' equity			
Class A and Class B shares	14	**521.9**	516.9
Contributed surplus		**2.6**	1.9
Retained earnings		**2,282.3**	2,036.0
Accumulated other comprehensive income	22	**(55.1)**	(33.1)
Retained earnings and accumulated other comprehensive income		**2,227.2**	2,002.9
		2,751.7	2,521.7
		$7,864.4	$7,305.2

N. C. Southern

DIRECTOR

W Simpson

DIRECTOR

Canadian Utilities Limited
Consolidated Statement of Cash Flows

(Millions of Canadian Dollars)

	Note	Three Months Ended December 31 2008	2007	Year Ended December 31 2008	2007
		(Unaudited)			
Operating activities					
Earnings attributable to Class A and Class B shares		**$ 114.2**	$ 98.7	**$ 413.1**	$ 386.7
Adjustments for:					
Depreciation and amortization		**100.5**	99.0	**389.1**	351.5
Future income taxes	3	**(8.8)**	(19.5)	**(4.3)**	(15.7)
TXU Europe settlement - net of income taxes	4	**(2.4)**	(2.5)	**(9.8)**	(11.1)
Mark to market of natural gas purchase and power generation revenue contracts	5	**1.6**	(4.0)	**2.8**	(4.1)
Other post employment benefit adjustment	20	**(2.1)**	-	**(9.4)**	-
Deferred availability incentives		**16.1**	4.5	**19.5**	2.2
Other		**5.4**	3.8	**3.6**	16.4
Funds generated by operations		**224.5**	180.0	**804.6**	725.9
Changes in non-cash working capital	17	**(79.2)**	(52.9)	**(12.8)**	(19.0)
Cash flow from operations		**145.3**	127.1	**791.8**	706.9
Investing activities					
Purchase of property, plant and equipment		**(376.3)**	(212.6)	**(1,010.9)**	(700.8)
Proceeds (costs) on disposal of property, plant and equipment		**(8.3)**	(14.7)	**(13.9)**	(16.2)
Contributions by utility customers for extensions to plant		**38.4**	25.8	**176.3**	91.2
Non-current deferred electricity costs		**17.6**	(4.5)	**10.5**	(9.6)
Deferred natural gas transmission costs		**-**	(0.6)	**(11.9)**	(3.1)
Change in receivable from joint venture		**0.7**	-	**(9.4)**	-
Changes in non-cash working capital	17	**25.3**	5.2	**37.4**	12.3
Other		**12.3**	(0.5)	**8.8**	(15.9)
		(290.3)	(201.9)	**(813.1)**	(642.1)
Financing activities					
Issue of long term debt	11	**4.0**	255.0	**370.7**	255.0
Repayment of long term debt	11	**(3.8)**	(50.0)	**(112.0)**	(50.0)
Repayment of non-recourse long term debt	4, 11	**(28.6)**	(12.3)	**(85.2)**	(122.8)
Issue of equity preferred shares by subsidiary		**-**	-	**-**	115.0
Redemption of equity preferred shares		**-**	-	**-**	(126.5)
Net issue of Class A shares		**0.1**	(7.7)	**5.0**	(6.4)
Dividends paid to Class A and Class B share owners		**(41.7)**	(39.6)	**(166.8)**	(156.8)
Changes in non-cash working capital	17	**(0.2)**	-	**(0.1)**	-
Other		**(1.1)**	(3.6)	**0.4**	(6.3)
		(71.3)	141.8	**12.0**	(98.8)
Foreign currency translation		**(3.2)**	(2.7)	**(11.3)**	(17.6)
Cash position [1]					
Increase (decrease)		**(219.5)**	64.3	**(20.6)**	(51.6)
Beginning of period		**946.1**	682.9	**747.2**	798.8
End of period		**$ 726.6**	$ 747.2	**$ 726.6**	$ 747.2

[1] Cash position consists of cash and short term investments less current bank indebtedness.

Canadian Utilities Limited
Consolidated Statement of Comprehensive Income

(Millions of Canadian Dollars)

		Three Months Ended December 31		Year Ended December 31	
	Note	**2008**	2007	**2008**	2007
		(Unaudited)			
Earnings attributable to Class A and Class B shares		**$ 114.2**	$ 98.7	**$413.1**	$386.7
Other comprehensive income, net of income taxes:					
Cash flow hedges	22	**(4.2)**	0.4	**(6.9)**	2.7
Foreign currency translation adjustment	22	**(5.4)**	(7.2)	**(15.1)**	(31.6)
		(9.6)	(6.8)	**(22.0)**	(28.9)
Comprehensive income		**$ 104.6**	$ 91.9	**$391.1**	$357.8

Canadian Utilities Limited
Notes to Consolidated Financial Statements
December 31, 2008

(tabular amounts in millions of Canadian dollars)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Financial Statement Presentation

The accompanying consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and include the accounts of Canadian Utilities Limited and its subsidiaries, including a proportionate share of joint venture investments (the "Corporation"). Principal operations are Utilities (ATCO Electric, ATCO Gas, ATCO Pipelines), Power Generation (ATCO Power, Alberta Power (2000)) and Global Enterprises (ATCO Midstream, ATCO Frontec, ATCO I-Tek). Significant joint venture investments consist principally of power generation plants; a substantial portion of Power Generation's operations are conducted through joint ventures. Additional joint venture investments exist for certain service contracts in ATCO Frontec.

Effective January 1, 2008, the Corporation adopted the Canadian Institute of Chartered Accountants ("CICA") recommendations for capital disclosures which require disclosure of qualitative and quantitative information regarding the Corporation's objectives, policies and processes for managing capital (see Note 15).

Effective January 1, 2008, the Corporation adopted the CICA recommendations pertaining to disclosure and presentation of financial instruments which require disclosure of the classification of the Corporation's financial instruments (as described in the Financial Instruments section below) and additional qualitative and quantitative information regarding the nature and extent of risks arising from financial instruments to which the Corporation is exposed (see Note 21).

Effective January 1, 2008, the Corporation adopted the CICA recommendations for measurement and disclosure of inventories which provide guidance on the determination of cost and its subsequent recognition as an expense, including any write-down to net realizable value, and on the cost formulas that are used to assign costs to inventories. The recommendations also clarified that major spare parts are to be included in property, plant and equipment. As a result of adopting these recommendations, the Corporation reclassified $1.8 million of inventories to property, plant, and equipment related to major spare parts on January 1, 2008.

Certain comparative figures have been reclassified to conform to the current presentation.

Rate Regulation

ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical, the ATCO Gas and ATCO Pipelines divisions of ATCO Gas and Pipelines Ltd. and the Battle River and Sheerness generating plants of Alberta Power (2000), all of which are wholly owned subsidiaries of Canadian Utilities Limited's wholly owned subsidiary, CU Inc., are collectively referred to in these consolidated financial statements as the "regulated operations". Accounting for rate regulated operations is described in Note 2.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Use of Estimates

The preparation of the Corporation's consolidated financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the year. On an on-going basis, management reviews its estimates, particularly those related to depreciation and amortization methods, useful lives and impairment of long-lived assets, amortization of deferred availability incentives, asset retirement obligations, employee future benefits and the fair value of financial instruments, using currently available information. Changes in facts and circumstances may result in revised estimates, and actual results could differ from those estimates.

Revenue Recognition

For regulated operations, revenues are recognized in a manner that is consistent with the underlying rate design as mandated by the regulator.

Revenues from ATCO Gas' regulated distribution of natural gas include variable charges, which are recognized on the basis of meter readings upon delivery of natural gas to customers and include an estimate of usage not yet billed, and fixed charges, based on the provision of the distribution service during the period.

Revenues from ATCO Electric's regulated distribution of electricity include variable charges, which are recognized on the basis of meter readings upon delivery of electricity to customers and include an estimate of usage not yet billed, and fixed charges, based on the provision of the distribution service during the period. Revenues for the use of ATCO Electric's regulated transmission facilities are based on an annual tariff and are recognized evenly throughout the year.

Revenues from ATCO Pipelines' regulated transmission of natural gas are recognized on the basis of contractual arrangements. For certain services, revenues are recognized on the basis of meter readings upon delivery of natural gas to customers and include an estimate of usage not yet billed.

Revenues from regulated sales and distribution of natural gas and electricity by other regulated operations, excluding Alberta Power (2000), are recognized upon delivery, primarily on the basis of meter readings, and include an estimate of usage not yet billed.

Revenues from generating plants are recognized upon delivery of output or upon availability of delivery as prescribed by contractual arrangements. Incentives and penalties associated with Alberta Power (2000)'s Power Purchase Arrangements ("PPA") are recognized as described under the accounting policy for deferred availability incentives.

Revenues from ATCO Midstream's natural gas storage and processing capacity are recognized on the basis of contractual arrangements, and revenues from the sale of natural gas liquids are recognized upon delivery.

Revenues from the supply of contracted services are recognized when products are delivered or services are provided.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Natural Gas Supply

Natural gas supply expense for regulated operations, which consists of natural gas volumes purchased for sales to customers, is based on actual costs incurred.

Natural gas supply expense for ATCO Midstream, which consists of natural gas volumes purchased for natural gas liquids extraction and sales to third parties, is based on actual costs incurred.

Purchased Power

Purchased power expense for regulated operations in the Yukon Territory and the Northwest Territories is based on the actual cost of electricity purchased. The amount included in customer rates in the Yukon Territory is based on actual costs and in the Northwest Territories is based on forecast cost. Revenues are adjusted for variances from forecast cost, and the variances are deferred until such time as approval from the regulator is obtained for refund to or collection from customers.

Income Taxes

The regulated operations follow the method of accounting for income taxes that is consistent with the method of determining the income tax component of their rates. When future income taxes are not provided in the income tax component of current rates, such future income taxes are not recognized to the extent that it is expected that they will be recovered from customers through inclusion in future rates.

Other subsidiaries follow the liability method of accounting for income taxes. Under this method, future tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Future tax liabilities and assets are measured using enacted and substantively enacted tax rates. The effect on future tax liabilities and assets of a change in tax rates is recognized in income in the period that the change occurs.

Cash and Short Term Investments

Short term investments consist of bankers' acceptances, certificates of deposit issued or guaranteed by credit worthy financial institutions and federal government issued short term investments with maturities generally of 90 days or less at purchase.

Inventories

Inventories are valued at the lower of cost or net realizable value. The cost of inventories is assigned using the weighted average cost method. Net realizable value is the estimated selling price in the ordinary course of business, less applicable variable selling expenses.

The cost of inventories is comprised of all costs of purchase, costs of conversion and other costs to bring the inventories to their present condition and location. The costs of purchase comprise the purchase price, import duties and non-recoverable taxes, and transport, handling and other costs directly attributable to the acquisition of finished goods, materials or services. The costs of conversion include direct material and labour costs and a systematic allocation of fixed and variable overheads incurred in converting materials into finished goods.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Property, Plant and Equipment

Property, plant and equipment are recorded at cost less accumulated depreciation and unamortized contributions by utility customers for extensions to plant.

Regulated operations include in property, plant and equipment an allowance for funds used during construction at rates approved by the Alberta Utilities Commission ("AUC") for debt and equity capital. Property, plant and equipment in the other subsidiaries include capitalized interest incurred during construction.

Certain regulated additions are made with the assistance of non-refundable cash contributions from customers when the estimated revenue is less than the cost of providing service or where special equipment is needed to supply the customers' specific requirements. These contributions are amortized on the same basis as, and offset the depreciation charge of, the assets to which they relate.

Depreciation is provided on assets on a straight-line basis over their estimated useful lives. Depreciation rates for regulated assets, excluding Alberta Power (2000)'s generating plants, are approved by the AUC and include a provision for future removal costs and site restoration costs (see the accounting policy for asset retirement obligations below). On retirement of these depreciable regulated assets, the accumulated depreciation is charged with the cost of the retired unit, net disposal costs and site restoration costs.

Property, plant and equipment and intangible assets with finite lives are tested for recoverability whenever events or changes in circumstances indicate a possible impairment. An impairment of property, plant and equipment and intangible assets with finite lives is recognized in earnings when the asset's carrying value exceeds the total cash flows expected from its use and eventual disposition. The impairment loss is then calculated as the difference between the asset's carrying value and its fair value, which is determined using discounted future cash flows.

Deferred Financing Charges

Issue costs of long term debt are amortized over the life of the debt using the effective interest method. Issue costs of preferred shares relating to regulated operations are amortized over the expected life of the issue and issue costs of preferred shares relating to other subsidiaries are charged to retained earnings. Unamortized premiums and issue costs of redeemed long term debt and preferred shares relating to regulated operations are amortized over the life of the issue funding the redemption. The Corporation's long term debt and non-recourse long term debt are reduced by the respective deferred financing charges.

Deferred Availability Incentives

Under the terms of the PPA's, the Corporation is subject to an incentive/penalty regime related to generating unit availability. Incentives are paid to the Corporation by the PPA counterparties for availability in excess of predetermined targets, whereas penalties are paid by the Corporation to the PPA counterparties when the availability targets are not achieved.

Accumulated incentives in excess of accumulated penalties are deferred. For any of the individual PPA's, should accumulated incentives plus estimated future incentives exceed accumulated penalties plus estimated future penalties, the excess will be amortized to revenues on a straight-line basis over the remaining term of the PPA's. Should accumulated penalties plus estimated future penalties exceed accumulated incentives plus estimated future incentives, the shortfall will be expensed in the year the shortfall occurs.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Asset Retirement Obligations

Asset retirement obligations are legal obligations associated with the retirement of tangible long lived assets. To the extent that they can be quantified, these obligations are measured and recognized at fair value, which is determined using discounted future cash flows.

An asset retirement obligation is recorded as a liability in deferred credits, with a corresponding increase to property, plant and equipment. The liability is accreted over the estimated time period until settlement of the obligation, with the accretion expense included in depreciation and amortization. The asset is depreciated over its estimated useful life.

Asset retirement obligations for regulated natural gas and electric transmission and distribution assets are not recognized as the Corporation expects to use the assets in service for an indefinite period. As such, no final removal date can be determined and, consequently, a reasonable estimate of the related retirement obligations cannot be made at this time. Asset retirement obligations have been recorded for the regulated and non-regulated electricity generating plants and the natural gas liquids extraction and processing plants.

Long Term Debt Due Within One Year

When the Corporation intends to refinance long term debt due within one year on a long term basis and there is a written undertaking from an underwriter to act on the Corporation's behalf with respect thereto, or sufficient capacity exists under long term bank loan agreements to issue commercial paper or assume bank loans, then long term debt due within one year is classified as long term.

Financial Instruments

The Corporation establishes the classification of financial instruments at their initial recognition. Financial assets are classified as held for trading, available for sale, held to maturity or loans and receivables. Financial liabilities are classified as held for trading or other liabilities.

Financial instruments classified as held for trading, other than derivative instruments that are effective hedging instruments, are measured at fair value with changes in fair value recognized in earnings. Derivatives that are designated as, and continue to be, effective cash flow hedging instruments have gains and losses in fair values recognized through other comprehensive income. Derivatives that are designated as fair value hedging instruments have gains and losses recognized in earnings.

Financial instruments classified as available for sale are measured at fair value using quoted prices in an active market. Changes in fair value are recognized in other comprehensive income until the item is derecognized or determined to be impaired, at which time the cumulative gain or loss previously reported in other comprehensive income is recognized in earnings. When actively quoted prices are not available, fair value is determined using other valuation techniques. If fair value cannot be reliably estimated, the item is carried at cost.

Financial instruments classified as held to maturity, loans and receivables or other liabilities are measured at fair value upon initial recognition but are subsequently measured at their amortized cost using the effective interest method.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Derivative Financial Instruments

In conducting its business, the Corporation uses various instruments, including forward contracts, swaps and options, to manage the risks arising from fluctuations in exchange rates, interest rates and commodity prices. All such instruments are used only to manage risk and not for trading purposes.

CICA recommendations require the recognition and measurement of derivative instruments embedded in host contracts that were issued, acquired or substantively modified on or after January 1, 2003. Derivative instruments embedded in host contracts that were issued, acquired or substantively modified prior to January 1, 2003 have not been identified and recognized in the consolidated financial statements as permitted by the recommendations.

The Corporation designates each derivative instrument as either a hedging instrument or a non-hedge derivative:

(a) A hedging instrument is designated as either:
   (i) a fair value hedge of a recognized asset or liability or,
   (ii) a cash flow hedge of either:
      - a specific firm commitment or anticipated transaction or,
      - the variable future cash flows arising from a recognized asset or liability.

   At inception of a hedge, the Corporation documents the relationship between the hedging instrument and the hedged item, including the method of assessing retrospective and prospective hedge effectiveness. At the end of each period, the Corporation assesses whether the hedging instrument has been highly effective in offsetting changes in fair values or cash flows of the hedged item and measures the amount of any hedge ineffectiveness. The Corporation also assesses whether the hedging instrument is expected to be highly effective in the future.

   A hedging instrument is recorded on the consolidated balance sheet at fair value. Payments or receipts on a hedging instrument that is determined to be highly effective as a hedge are recognized concurrently with, and in the same financial category as, the hedged item. Subsequent changes in the fair value of a fair value hedge are recognized in earnings concurrently with the hedged item. For a cash flow hedge, the effective portion of changes in fair value is recognized in other comprehensive income and is subsequently transferred to earnings concurrently with the hedged item, whereas the portion of the changes in fair value that is not effective at offsetting the hedged exposure is recognized in earnings.

   If a hedging instrument ceases to be highly effective as a hedge, is de-designated as a hedging instrument or is settled prior to maturity, then the Corporation ceases hedge accounting prospectively for that instrument; for a cash flow hedge, the gain or loss deferred to that date remains in accumulated other comprehensive income and is transferred to earnings concurrently with the hedged item. Subsequent changes in the fair value of that derivative instrument are recognized in earnings.

   If the hedged item is sold, extinguished or matures prior to the termination of the related hedging instrument, or if it is probable that an anticipated transaction will not occur in the originally specified time frame, then the gain or loss deferred to that date for the related hedging instrument is immediately transferred from accumulated other comprehensive income to earnings.

Hedge gains or losses that were recognized in other comprehensive income are added to the initial carrying amount of a non-financial asset or non-financial liability when:

(i) an anticipated transaction for a non-financial asset or non-financial liability becomes a specific firm commitment for which fair value hedge accounting is applied or,

(ii) a cash flow hedge of an anticipated transaction subsequently results in the recognition of the non-financial asset or non-financial liability.

(b) A non-hedge derivative instrument is recorded on the consolidated balance sheet at fair value and subsequent changes in fair value are recorded in earnings.

The Corporation applies settlement date accounting to the purchases and sales of financial assets. Settlement date accounting implies the recognition of an asset on the day it is received by the Corporation and the recognition of the disposal of an asset on the day that it is delivered by the Corporation. Any gain or loss on disposal is also recognized on that day.

Transaction costs that are directly attributable to the acquisition or issue of financial assets or financial liabilities that are not held for trading are added to the fair value of such assets or liabilities at time of initial recognition.

Employee Future Benefits

The Corporation accrues for its obligations under defined benefit pension and other post employment benefit ("OPEB") plans. Costs of these benefits are determined using the projected benefits method prorated on service and reflects management's best estimates of investment returns, wage and salary increases, age at retirement and expected health care costs.

Pension plan assets at the end of the year are reported at market value. The expected long term rate of return on plan assets is determined at the beginning of the year on the basis of the long bond yield rate at the beginning of the year plus an equity and management premium that reflects the plan asset mix. Expected return on plan assets for the year is calculated by applying the expected long term rate of return to the market related value of plan assets, which is the average of the market value of plan assets at the end of the preceding three years.

Accrued benefit obligations at the end of the year are determined using a discount rate that reflects market interest rates that match the timing and amount of expected benefit payments. Due to the recent, unprecedented events in the financial markets associated with the current credit environment which has resulted in significantly higher yields than normal, the current discount rate selection methodology has been refined to include high quality corporate bonds and quasi-government organizations. This resulted in a liability discount rate of 7%, an increase of 1.5% from the prior year (see Note 20).

Experience gains and losses and the effect of changes in assumptions in excess of 10% of the greater of the accrued benefit obligations or the market value of plan assets, adjustments resulting from plan amendments and the net transitional liability or asset, which arose upon the adoption in 2000 of the current accounting standard, are amortized over the estimated average remaining service life of employees.

In June 2008, the Corporation prospectively changed the method of apportioning the costs of OPEB plans to individual subsidiaries. Formerly, each subsidiary was apportioned a percentage of its payroll costs at a rate calculated for the plan as a whole. The revised method determines the accrued OPEB liabilities and

costs on a company-by-company basis. Total consolidated accrued OPEB liabilities and costs did not change. Under the new method of apportioning, the OPEB liability for the regulated subsidiaries, excluding Alberta Power (2000), increased by $10.4 million with a corresponding increase to non-current regulatory assets. Pursuant to an AUC decision effective January 1, 2000, the regulated operations, excluding Alberta Power (2000), are required to expense contributions for other post employment benefit and certain other defined benefit pension plans as paid. Consequently, there was no change to their earnings for the unaudited three months and year ended December 31, 2008. The difference between the amounts accrued and paid is deferred in non-current regulatory assets.

The OPEB liability for Alberta Power (2000) and the non-regulated subsidiaries decreased which resulted in an increase to earnings of $7.0 million, of which $5.5 million was recorded in the second quarter of 2008 and $1.5 million was recorded in the fourth quarter of 2008.

Employer contributions to the defined contribution pension plans are expensed as paid.

Stock Based Compensation Plans

The Corporation expenses stock options granted on and after January 1, 2002; no compensation expense is recorded for stock options granted prior to January 1, 2002 as permitted by GAAP. The Corporation determines the fair value of the options on the date of grant using an option pricing model and recognizes the fair value over the vesting period of the options granted as compensation expense and contributed surplus. Contributed surplus is reduced as the options are exercised and the amount initially recorded in contributed surplus is credited to Class A and Class B share capital.

No compensation expense is recognized when share appreciation rights are granted. Prior to vesting, compensation expense arising from an increase or decrease in the market price of the shares over the base value of the rights is accrued equally over the remaining months to the date of vesting. After that date, compensation expense arising from an increase or decrease in the market price of the shares is recognized monthly in earnings.

Foreign Currency Translation

Assets and liabilities of self-sustaining foreign operations are translated into Canadian dollars at the rate of exchange in effect at the balance sheet date and revenues and expenses are translated at the average monthly rates of exchange during the year. Gains or losses on translation of self-sustaining foreign operations are included in accumulated other comprehensive income in share owners' equity.

Monetary assets and liabilities of integrated foreign operations, as well as non-monetary assets carried at market value, are translated into Canadian dollars at the rate of exchange in effect at the balance sheet date. Other non-monetary assets and non-monetary liabilities are translated at rates of exchange in effect when the assets were acquired or liabilities incurred. Revenues and expenses are translated at the average monthly rates of exchange during the year; depreciation and amortization are translated at rates of exchange consistent with the assets to which they relate. Gains or losses on translation of integrated foreign operations are recognized in earnings.

Transactions undertaken by Canadian operations that are denominated in foreign currencies are translated into Canadian dollars at the rate of exchange in effect at the transaction date. Monetary items and non-monetary items that are carried at market value arising from a transaction denominated in a foreign currency are adjusted to reflect the rate of exchange in effect at the balance sheet date. Gains or losses on translation of such monetary and non-monetary items are recognized in earnings.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Future Accounting Changes

Effective for the Corporation beginning January 1, 2009, the CICA has removed a temporary exemption in its accounting recommendations that permitted assets and liabilities arising from rate regulation to be recognized and measured on a basis other than in accordance with the primary sources of GAAP. As permitted by Canadian GAAP, the Corporation will use standards issued by the Financial Accounting Standards Board in the United States that allow for the recognition and measurement of rate regulated assets and liabilities as another source of Canadian GAAP. The adoption of these standards is not expected to have a material impact on the earnings of the Corporation. However, it is anticipated that the reserves for future removal and site restoration costs, which are currently netted against property, plant and equipment, will be reclassified to non-current liabilities, resulting in an increase to the Corporation's total assets and liabilities. The amount of such future removal and site restoration costs at December 31, 2008 was $461.2 million. The CICA has also issued new recommendations that will require the recognition of future income tax assets and liabilities as well as a separate regulatory asset or liability for the amount of future income taxes expected to be included in future rates and recovered from or paid to future customers. The amount of unrecorded future income tax liabilities of the regulated operations at December 31, 2008 was $192.2 million. Upon adoption of the new standard, the Corporation expects to record an increase in future income tax liabilities and non-current regulatory assets of approximately $255 million. The additional amount reflects the future income tax effects of the settlement mechanism of the regulatory assets through customer rates that would occur in the future periods. These recommendations will be applied prospectively.

The CICA has issued new accounting recommendations for goodwill and intangible assets which establish standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets (including internally developed intangible assets). These recommendations are effective for the Corporation beginning January 1, 2009. Goodwill and intangible assets that are not assets as defined by GAAP will be derecognized and charged to the equity of the Corporation at that date. The adoption of these recommendations is not expected to have a material impact on the earnings or assets of the Corporation.

The Canadian Accounting Standards Board confirmed in 2008 that the use of International Financial Reporting Standards ("IFRS") by publicly accountable enterprises will be required in 2011. The Corporation will need to begin reporting under IFRS in the first quarter of 2011 with comparative data for the prior year. IFRS uses a conceptual framework similar to Canadian GAAP, but there could be significant differences in recognition, measurement and disclosures that will need to be addressed.

The Corporation has established a Steering Committee, a project team, and working groups to review the adoption of IFRS. The project team and working groups provide position papers and regular updates to management, the Steering Committee and the Audit Committee. Education sessions have been, and will continue to be, provided for employees, senior management and the Audit Committee to increase knowledge and awareness of IFRS and its impacts. An external expert advisor has been engaged. The Corporation is participating in various industry groups, including the Canadian Energy Pipeline Association, the Canadian Gas Association and the Canadian Electric Association.

The Corporation's IFRS Conversion Project consists of three phases: Assessment and Diagnostic; Design and Planning; and Implementation and Review. Position papers are being prepared on issue-specific accounting differences between Canadian GAAP and IFRS and the impact on financial reporting computer systems. These position papers are being reviewed with the Corporation's auditors. As a number of the IFRS standards are changing, the position papers will be updated to reflect any changes

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

resulting from the final standards. The Corporation is also evaluating the potential impact of IFRS on financial covenants, business contracts and internal controls over financial reporting.

The Corporation reviews discussion papers, exposure drafts and standards released by the International Accounting Standards Board and the International Financial Reporting Interpretations Committee. The Corporation will continue to assess the impact of the proposed standards on its financial statements and disclosure as additional information becomes available. Financial impacts cannot be reasonably determined at this time.

Based on initial assessments the Corporation has identified that the following areas have the greatest potential impact to the Corporation's accounting: property, plant and equipment, joint arrangements, leases, rate regulated operations, deferred availability incentives and employee benefits. There will also be a significant amount of effort to comply with the IFRS' requirements for initial adoption of IFRS.

A more detailed analysis and evaluation of the financial impact of the issues identified in the assessment and diagnostic phases and the impact on and implementation of financial reporting computer systems will be completed in 2009.

2. ACCOUNTING FOR RATE REGULATED OPERATIONS

Nature and economic effects of rate regulation

ATCO Electric, ATCO Gas and ATCO Pipelines (the "utilities") are regulated primarily by the AUC, which, effective January 1, 2008, succeeded the Alberta Energy and Utilities Board as regulator for the utilities industry. The AUC administers acts and regulations covering such matters as rates, financing, accounting, construction, operation and service area.

The Battle River and Sheerness generating plants of Alberta Power (2000) were regulated by the AUC until December 31, 2000 but are now governed by legislatively mandated PPA's that were approved by the AUC. These plants are included in regulated operations primarily because the PPA's are designed to allow the owners of generating plants constructed before January 1, 1996 to recover their forecast fixed and variable costs and to earn a return at the rate specified in the PPA's. Each plant will become deregulated upon the earlier of one year after the expiry of its PPA or a decision to continue to operate the plant. For PPA's expiring prior to 2019, Alberta Power (2000) has one year after the expiry of a PPA to determine whether to decommission the generating plant in order to fully recover plant decommissioning costs or to continue to operate the plant and be responsible for the decommissioning costs. For PPA's expiring after 2018 decommissioning costs are the responsibility of the plant owner. Each PPA is to remain in effect until the earlier of the last day of the estimated life of the related generating plant or December 31, 2020.

The utilities are subject to a cost of service regulatory mechanism under which the AUC establishes the revenues required (i) to recover the forecast operating costs, including depreciation and amortization and income taxes, of providing the regulated service, and (ii) to provide a fair and reasonable return on utility investment, or rate base. Whereas actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns.

2. ACCOUNTING FOR RATE REGULATED OPERATIONS (continued)

Rate base for each utility is the aggregate of the AUC approved investment in property, plant and equipment, less accumulated depreciation, and unamortized contributions by utility customers for extensions to plant, plus an allowance for working capital. The utilities earn a return on rate base intended to meet the cost of the debt and preferred share components of rate base and to provide share owners with a fair return on the common equity component of rate base.

The AUC approves rates of return for the debt and preferred share components of rate base based on the actual or forecast weighted average cost of each utility's debt and preferred shares and establishes the capital structure for each utility. On July 2, 2004, the AUC established a standardized approach for determining the rate of return on common equity for each utility regulated by the AUC. This rate of return will be adjusted annually by 75% of the change in long term Government of Canada bond yield as forecast in the November Consensus Forecast, adjusted for the average difference between the 10 year and 30 year Government of Canada bond yields for the month of October as reported in the National Post. The generic return on equity determined on an annual basis in accordance with the generic cost of capital decision applies to each year of the test period in the utilities' applications. If no rate applications are filed for a particular year, then there will be no adjustment to the common equity rate of return for that year. The rate of return was 8.75% for 2008 (2007 - 8.51%) and has been set at a placeholder rate of 8.75% for 2009.

Under the cost of service methodology, the utilities seek approval for their revenue requirement either through submission of general rate applications to the AUC or a negotiated settlement process with interested parties. In the latter case, the AUC monitors the negotiated settlement process and any agreement that is reached is subject to AUC approval. The AUC may approve interim rates or approve the recovery of costs on a placeholder basis, subject to final determination.

Financial statement effects of rate regulation

Certain items in these consolidated financial statements are accounted for differently than they would be in the absence of rate regulation. CICA recommendations do not require that assets and liabilities arising from rate regulation be recognized and measured in accordance with the primary sources of GAAP.

Where regulatory decisions dictate, the utilities defer certain costs or revenues as assets or liabilities on the balance sheet and record them as expenses or revenues in the earnings statement as they collect or refund amounts through future customer rates. Any adjustments to these deferred amounts are recognized in earnings in the period that the AUC renders a decision concerning these adjustments.

Circumstances in which rate regulation affects the accounting for a transaction or event are described below. For these regulatory items, the expected recovery or settlement period, or likelihood of recovery or settlement, is affected by risks and uncertainties relating to the ultimate authority of the regulator in determining the item's treatment for rate setting purposes, and, unless specifically indicated, is indeterminate.

2. ACCOUNTING FOR RATE REGULATED OPERATIONS (continued)

The regulatory assets and liabilities comprise the following:

	2008	2007
Regulatory assets – current:		
Deferred electricity costs	**$ 26.1**	$ 1.5
Current income tax savings associated with future income tax refund to customers	**1.9**	2.0
Deferred load balancing transactions	**2.9**	10.1
Deferral of unused vacation costs	**14.7**	13.9
Other regulatory assets [1]	**10.2**	2.5
	$ 55.8	$ 30.0
Regulatory assets – non-current:		
Regulatory other post employment benefits asset (Note 20)	**$ 46.9**	$ 32.3
Deferred electricity costs	**-**	17.4
Current income tax savings associated with future income tax refund to customers	**5.2**	7.0
Deferred hearing costs [1]	**8.4**	4.0
Reserves for injuries and damages	**-**	1.5
Other regulatory assets [1]	**4.8**	13.4
	$ 65.3	$ 75.6
Regulatory liabilities – current:		
Deferred electricity cost recoveries	**$ 5.6**	$ -
Deferred load balancing transactions	**20.9**	5.9
Other regulatory liabilities [1]	**2.8**	-
	$ 29.3	$ 5.9
Regulatory liabilities – non-current:		
Regulatory pension liability (Note 20)	**$110.2**	$110.0
Deferred royalty credits	**23.3**	23.1
Deferred electricity cost recoveries	**-**	7.0
Reserves for injuries and damages	**3.3**	2.1
Other regulatory liabilities [1]	**11.8**	4.3
	$148.6	$146.5

(1) Amortization of certain regulatory assets and liabilities, which are recorded in depreciation and amortization, amounted to $17.7 million (2007 – $7.7 million).

Employee future benefits

The Corporation accrues for its obligations under defined benefit pension and other post employment benefit plans. The regulatory asset (liability) reflects an AUC decision, effective January 1, 2000, to record costs of employee future benefits in the utilities when paid rather than accrued. The variances between the amounts paid and accrued for each of the defined benefit pension plans and the other post employment benefit plans will vary depending on the performance of plan assets and the actuarial valuations of plan obligations. These variances will be deferred until the plans are paid, settled or terminated.

GAAP requires that the variances between the amounts accrued and paid be recognized as an expense or reduction in expense in the period in which they are accrued. Consequently, defined benefit pension plan cost in 2008 would have been $0.9 million lower (2007 – $7.8 million higher), and other post

employment benefit plan cost in 2008 would have been $2.4 million higher (2007 – $2.9 million higher), in the absence of rate regulation.

Upon the adoption of the current accounting standard in 2000, the utilities had recorded deferred pension assets of $23.0 million. The utilities have been earning an AUC approved rate of return on these assets through customer rates as the assets form part of the utilities' AUC approved rate base. In the absence of rate regulation, the utilities would not be able to earn a return on these assets. Consequently, revenues in 2008 would have been $1.2 million lower (2007 – $1.6 million lower). On October 11, 2006, the AUC issued a decision that approved recovery of these assets for a nine-year period commencing January 1, 2005 and permitted the utilities to continue to earn an AUC approved rate of return on the unrecovered portion of these assets over the recovery period. In 2008, the utilities amortized $3.4 million (2007 – $2.6 million) of the deferred pension asset.

Deferred electricity costs (recoveries)

Variances between ATCO Electric's actual and forecast transmission access payments may arise due to changes in tariffs charged by the Alberta Power Pool. The amount included in customer rates is based on forecast cost. Revenues are adjusted for changes in tariffs, and the variances are deferred until approval from the AUC is obtained for refund to or collection from customers, which is expected to occur in the following year. GAAP requires that revenues be based on the rates approved by the AUC and not adjusted for variances between forecast and actual costs.

In Alberta, major transmission capital projects are planned by the Alberta Power Pool and directly assigned to one of the transmission facility owners in the province. Revenue requirement includes a return on forecast rate base. Whereas actual capital costs may vary from forecast capital costs, variances may arise between the return on forecast rate base and the return on actual rate base. Revenues are adjusted for these variances, and the variances are deferred until approval from the AUC is obtained for refund to or collection from the Alberta Power Pool, which is expected to occur in the following year. GAAP requires that revenues be based on the rates approved by the AUC and not adjusted for variances between the returns on forecast and actual rate base.

Variances between ATCO Electric's actual and forecast income tax provision may arise due to changes in enacted and substantively enacted tax rates. The amount included in customer rates is based on forecast tax rates. Revenues are adjusted for changes in enacted and substantively enacted tax rates, and the variances are deferred until approval from the AUC is obtained for refund to or collection from customers, which is expected to occur in the following year. GAAP requires that revenues be based on customer rates approved by the AUC and not adjusted for variances between forecast and actual tax rates.

Consequently, revenues in 2008 would have been $8.6 million lower (2007 – $9.4 million lower) in the absence of rate regulation.

Current income tax savings associated with future income tax refund to customers

The AUC directed ATCO Electric to change its income tax methodology for federal purposes, whereby, effective January 1, 2007, ATCO Electric no longer recognizes future income taxes, and to refund to customers the future income taxes of $34.4 million collected under the previously allowed tax methodology (see Note 3). This change in tax methodology does not affect earnings as ATCO Electric's revenues and income tax expense were reduced by similar amounts. Accordingly, in 2007, ATCO Electric recorded a reduction in future income tax liabilities of $34.4 million and a liability to customers of $48.6 million, offset by a regulatory asset of $14.2 million which represents current income tax

2. ACCOUNTING FOR RATE REGULATED OPERATIONS (continued)

savings to be realized in future periods. Unrecorded future income tax liabilities increased by $34.4 million as a result of this decision.

In December 2007, ATCO Electric refunded $16.1 million of the liability to transmission customers reducing the liability to customers to $32.5 million. In addition, the $16.1 million refund resulted in current income tax savings of $5.2 million, reducing the regulatory asset to $9.0 million. The total reduction in revenues and income taxes in 2007 was $39.6 million. ATCO Electric began refunding the remaining $32.5 million to distribution customers over a five year period commencing in 2008. ATCO Electric will realize the regulatory asset of $9.0 million over the same 5 year period with no effect on earnings as current income tax savings will be offset by this reduction in revenues.

Consequently, revenues for 2008 would have been $2.0 million higher (2007 – $9.0 million lower) in the absence of rate regulation. Assets of $1.9 million (2007 – $2.0 million) are included in current regulatory assets and $5.2 million (2007 – $7.0 million) are included in non-current regulatory assets in the balance sheet.

Deferred load balancing transactions

ATCO Pipelines has received AUC approval to establish deferral accounts to collect the costs and revenues arising from load balancing transactions. Load balancing requires the purchase or sale of natural gas to maintain appropriate operating pressures on ATCO Pipelines' North and South transmission pipeline systems. Should the deferral account for either North or South exceed $2.0 million, ATCO Pipelines may submit an application to the AUC requesting recovery from or refund to customers of that particular deferral amount. On January 29, 2009, a decision was received that increases these amounts to $7.5 million for the North and $5.0 million for the South. GAAP requires that actual revenues and costs be recognized in the period in which they are earned or incurred. Consequently, revenues in 2008 would have been $22.2 million higher (2007 – $4.7 million higher) in the absence of rate regulation. Assets of $2.9 million (2007 - $10.1 million) are included in current regulatory assets, and liabilities of $20.9 million (2007 - $5.9 million) are included in current regulatory liabilities in the balance sheet.

Deferral of unused vacation costs

Revenue requirement includes a recovery from customers for vacation entitlement taken by employees during the year. A portion of the vacation entitlement is earned by employees and accrued as a liability in the prior year. GAAP requires that the vacation pay liability be expensed in the year accrued and not adjusted for amounts that will be recovered from customers. Consequently, expenses for 2008 would have been $0.8 million higher in the absence of rate regulation.

Deferred hearing costs

The utilities incur hearing costs on an ongoing basis associated with various AUC regulatory proceedings. These costs are comprised primarily of legal and consulting expenses incurred by the utilities in addition to costs incurred by intervenor groups that have been reimbursed by the utilities as directed by the AUC. Hearing costs are deferred to the balance sheet and are amortized using AUC approved annual amounts that are collected through customer rates. Variances between the approved annual amounts and actual costs incurred are deferred until the next general rate application or until a specific application is made to the AUC requesting recovery from or refund to customers. GAAP requires that hearing costs be expensed in the period in which they are incurred. Consequently, expenses in 2008 would have been $4.4 million higher (2007 – $3.0 million higher) in the absence of rate regulation.

2. ACCOUNTING FOR RATE REGULATED OPERATIONS (continued)

Reserves for injuries and damages

The AUC has approved the use of reserves for injuries and damages by the utilities as a means of self-insurance. The reserves for injuries and damages are established based on annual amounts approved by the AUC to be amortized by each utility and collected through customer rates. Variances between the approved annual amounts and actual costs incurred are deferred until the following general rate application or until a specific application is made to the AUC requesting recovery from or refund to customers. GAAP requires that claims be expensed in the period in which they are incurred. Consequently, expenses in 2008 would have been \$1.6 million lower (2007 – \$1.2 million higher) in the absence of rate regulation.

For Alberta Power (2000), reserves for injuries and damages are recoverable under the terms of the PPA's on a straight line basis through 2008. GAAP requires that claims be expensed in the period in which they are incurred. Consequently, expenses in 2008 would have been \$1.0 million lower (2007 – \$1.0 million lower) in the absence of rate regulation.

Deferred royalty credits

Under the terms of PPA's, the compensation for certain royalties incurred by Alberta Power (2000) for coal supply are averaged over the term of each PPA. As such, royalty costs incurred are deferred and expensed on the same average cost basis as reflected in the underlying PPA revenues. GAAP requires that royalty costs be expensed in the period in which they are incurred. Consequently, expenses in 2008 would have been \$0.2 million lower (2007 – \$3.4 million lower) in the absence of rate regulation.

Other regulatory assets and liabilities

Other regulatory assets and liabilities include the following:

a) ATCO Pipelines has received AUC approval to defer the variances between actual and AUC approved forecast revenues and costs associated with the movement (receipt or delivery) of natural gas between ATCO Pipelines' system and other connected pipeline systems. ATCO Pipelines has applied for approval to recover these deferral account balances in its general rate application which was filed with the AUC on October 1, 2007. GAAP requires that actual revenues and costs be recognized in the period in which they are earned or incurred.

   Consequently, revenues in 2008 would have been \$0.6 million higher (2007 – \$0.1 million higher) and expenses would have been \$0.4 million lower (2007 – \$0.2 million lower) in the absence of rate regulation. Assets of \$0.3 million and \$1.9 million (2007 – \$2.5 million and \$0.2 million) are included in current regulatory assets and non-current regulatory assets, respectively, and liabilities of \$1.4 million and \$0.1 million are included in current and non-current regulatory liabilities respectively (2007 – \$0.9 million in non-current regulatory liabilities).

b) ATCO Pipelines has received AUC approval to establish a deferral account for the Salt Cavern Storage facility to collect (i) the revenue requirements for return on rate base and associated income taxes related to the necessary working capital for the natural gas in storage, and (ii) the gains or losses associated with the sale of natural gas in the market upon withdrawal from storage. ATCO Pipelines is required to submit an application to the AUC, either separately or in conjunction with a general rate application for that particular year, requesting recovery from or refund to customers of the deferral amount should the deferral account exceed \$2.0 million at the end of the annual injection/withdrawal cycle on March 31 of a particular year. ATCO Pipelines has applied for approval to recover this

deferral account balance in its general rate application which was filed with the AUC on October 1, 2007. GAAP requires that actual revenues and costs be recognized in the period in which they are earned or incurred. Consequently, revenues in 2008 would have been \$1.9 million lower (2007 – \$2.2 million lower) in the absence of rate regulation. Assets of \$7.8 million are included in current regulatory assets (2007 – \$5.9 million included in non-current regulatory assets) in the balance sheet.

c) ATCO Electric, ATCO Gas and ATCO Pipelines have provided interest free market differential loans to employees when relocating; however, ATCO Electric's revenue requirement includes a recovery from customers for imputed interest on these loans. The CICA recommendations regarding the measurement of financial assets require that these loans be measured at fair value, resulting in a reduction in their carrying amount. ATCO Electric defers the variances between the fair value and face value of the loans as a regulatory asset. GAAP requires that the variances be recorded as compensation expense upon issue of the loans, with subsequent accretion according to the effective interest method over their respective terms. Consequently, revenues for 2008 would have been \$0.1 million lower (2007 – \$1.1 million lower) in the absence of rate regulation. Assets of \$2.6 million (2007 - \$2.5 million) are included in non-current regulatory assets.

d) ATCO Gas, pursuant to an AUC decision, has received approval to establish deferral accounts to collect the costs and revenues arising from load balancing transactions. Load balancing requires the purchase or sale of natural gas to maintain appropriate operating pressures on ATCO Gas' North and South distribution pipeline systems. Should the deferral account for either the North or South exceed \$2.0 million over three successive months, ATCO Gas may submit an application to the AUC requesting recovery from or refund to customers of that particular deferral account. GAAP requires that actual revenues and costs be recognized in the period in which they are earned or incurred. Consequently, revenues in 2008 would have been \$4.4 million higher (2007 - nil) in the absence of rate regulation. Liabilities of \$4.4 million are included in non-current regulatory liabilities in the balance sheet (2007 – nil).

e) ATCO Gas has received AUC approval to establish deferral accounts to mitigate the impact of temperature fluctuations on its revenues. Should the deferral account for either the North or the South exceed \$7.0 million at April 30th of any year, ATCO Gas may submit an application to the AUC requesting recovery from or refund to customers of that particular deferral account. GAAP requires that the temperature impacted revenues be recognized in the period in which they are realized. Consequently, revenues in 2008 would have been \$2.7 million higher (2007 – nil) in the absence of rate regulation. Liabilities of \$2.7 million (2007 – nil) are included in non-current regulatory liabilities in the balance sheet.

Other items affected by rate regulation

The AUC permits an allowance for funds used ("AFU"), based on each utility's weighted average cost of capital, to be included in rate base. AFU is also included in the cost of property, plant and equipment for financial reporting purposes, and is depreciated as part of the total cost of the related asset, based on the expectation that depreciation expense, including the AFU component, will be approved for inclusion in future customer rates. Since AFU includes preferred share and common equity components, it exceeds the amount allowed to be capitalized in similar circumstances in the absence of rate regulation.

The utilities and the generating plants of Alberta Power (2000) follow the method of accounting for income taxes that is consistent with the method of determining the income tax component of its rates. When future income taxes are not included in the income tax component of current rates, such future

2. ACCOUNTING FOR RATE REGULATED OPERATIONS (continued)

income taxes are not recognized to the extent that they will be recovered from customers through inclusion in future rates. GAAP requires the recognition of all future income tax liabilities and future tax assets in the absence of rate regulation (see Note 6).

3. REGULATORY MATTERS

In September 2007, ATCO Electric received a decision on its General Tariff Application for 2007 and 2008 which approved a return on common equity of 8.75% for 2008 and 8.51% for 2007. The effect of the decision on the earnings of ATCO Electric was not material.

The decision also directed ATCO Electric to change its income tax methodology for federal purposes. This change in tax methodology does not affect earnings as ATCO Electric's revenues and income tax expense were reduced by similar amounts. Accordingly, in 2007, ATCO Electric recorded a reduction in future income tax liabilities of $34.4 million and a liability to customers of $48.6 million, offset by a regulatory asset of $14.2 million which represents current income tax savings to be realized in future periods. Unrecorded future income tax liabilities increased by $34.4 million as a result of this decision.

In December 2007, ATCO Electric refunded $16.1 million of the liability to transmission customers reducing the liability to customers to $32.5 million. In addition, the $16.1 million refund resulted in current income tax savings of $5.2 million, reducing the regulatory asset to $9.0 million. The total reduction in revenues and income taxes in 2007 was $39.6 million ATCO Electric began refunding the remaining $32.5 million to distribution customers over a five year period commencing in 2008. ATCO Electric will realize the regulatory asset of $9.0 million over the same 5 year period with no effect on earnings as current income tax savings will be offset by this reduction in revenues.

In July 2008, ATCO Electric filed a general tariff application with the AUC for 2009 and 2010 requesting, among other things, increased revenues to recover increased financing, depreciation and operating costs associated with increased rate base in Alberta. ATCO Electric filed an application requesting interim refundable rates pending the AUC's decision on the application. In December 2008, ATCO Electric received a decision from the AUC approving interim refundable rate increases amounting to 50% of the requested increase for transmission operations and 25% of the requested increase for distribution operations. A hearing is scheduled for February 2009, with a decision expected by the third quarter in 2009.

In November 2007, ATCO Gas filed a general rate application with the AUC for 2008 and 2009 requesting, among other things, increased revenues to recover increased financing, depreciation and operating costs associated with increased rate base in Alberta. ATCO Gas also filed an application requesting interim adjustable rates pending the AUC's decision on the general rate application. In December 2007, ATCO Gas received a decision from the AUC approving interim adjustable rate increases amounting to 50% of ATCO Gas' requested revenue increase.

In November 2008, ATCO Gas received a decision on its general rate application for 2008 and 2009 which was filed in November 2007. The decision established the amount of revenue requirement ATCO Gas can recover through distribution rates for natural gas distribution service to its customers for 2008 and 2009.

The effect of the decision on ATCO Gas' 2008 earnings was not materially different than the impact of the interim rates approved in December 2007. Other items of note stemming from the decision included: (i) the AUC direction to use the existing 38% common equity as a placeholder in its 2008 and 2009

3. REGULATORY MATTERS (continued)

revenue requirements until such time as the AUC issued further direction; (ii) the AUC direction to use the forecast 2008 and 2009 information and technology and customer care and billing costs submitted in the general rate application as placeholders pending the completion of the benchmarking process; (iii) to use the forecast 2008 and 2009 income tax amounts submitted in the general rate application until a further proceeding, currently scheduled to occur in the first quarter of 2009, is held to determine the proper regulatory treatment that can be accorded to the cost increases/reductions occasioned by income tax reassessments, deferral accounts for income tax purposes, and ATCO Gas' treatment of capital outlays as current expenditures for income tax purposes; and (iv) the AUC approval to establish deferral accounts deferring the impact of temperature fluctuations on ATCO Gas' revenues commencing January 1, 2008.

In May 2008, the Alberta Court of Appeal issued a decision in which it held that the AUC had erred in law or jurisdiction when it included ATCO Gas' Carbon storage facility in rate base for the purpose of generating revenues to offset customer rates. As a result of the Alberta Court of Appeal's decision, ATCO Gas requested and received approval from the AUC effective July 1, 2008 to suspend rate riders to customer rates on an interim basis. The suspension of the rate riders increased earnings for the unaudited three months and year ended December 31, 2008 by $1.0 million and $4.4 million, respectively. Additionally, ATCO Gas, on July 11, 2008, filed a compliance application with the AUC requesting removal of the Carbon facility from the utility rate base and revenue requirement effective April 1, 2005, consistent with the Alberta Court of Appeal decision.

In October 2007, ATCO Pipelines filed a general rate application for 2008 and 2009 requesting, among other things, increased revenues to recover increased financing, depreciation and operating costs associated with an increased rate base in Alberta. In November 2007, ATCO Pipelines filed an application requesting interim adjustable rates pending the AUC's decision on the general rate application. In December 2007, ATCO Pipelines received a decision from the AUC approving interim adjustable rate increases amounting to 40% of ATCO Pipelines' requested revenue increase.

In November 2008, ATCO Pipelines filed an application requesting the AUC to approve a negotiated settlement with its customers of ATCO Pipelines' 2008 and 2009 revenue requirements in accordance with its general rate application. A decision on the application is expected in the first quarter of 2009.

Also, in November 2008, the AUC approved ATCO Pipelines application for revised interim rates effective December 1, 2008 to collect 60% of its requested revenue increase.

In January 2009, ATCO Pipelines filed an application requesting AUC approval to commence negotiations with its customers to settle ATCO Pipelines' revenue requirements for each of the years 2010, 2011, and 2012.

In February 2008, the AUC initiated a generic proceeding to determine whether the standardized rate of return methodology and the utility capital structures should be reviewed. A regulatory process has been established by the AUC with a hearing currently scheduled for May 19, 2009, to review the generic return on equity formula as well as to review the capital structure for each of the Alberta utilities. The AUC also indicated that any changes which result from this proceeding would be applied beginning in 2009. As ATCO Gas filed a general rate application for 2008 and 2009, a separate module within the generic proceeding will address 2008 cost of capital issues relating to the capital structure for ATCO Gas, as inclusion of these issues was removed from its 2008/2009 general rate application. The changes for 2008 and 2009 will not apply to ATCO Pipelines if its negotiated settlement for 2008 and 2009 revenue requirements is approved by the AUC.

3. REGULATORY MATTERS (continued)

A process continues with respect to the pricing of services provided by ATCO I-Tek to the utilities. A benchmarking report was received in January 2008 and filed with the AUC in February 2008, along with an application to adjust placeholders. In April 2008, an agreement with the customer group concerning the adjustment to placeholders was submitted to the AUC for approval. Should this agreement be approved by the AUC, it is not expected to have a material impact on consolidated earnings. The AUC has established a further process with a hearing scheduled for the second quarter of 2009 to review the issues related to the application and subsequent agreement with the customer group.

The Corporation has a number of other regulatory filings and regulatory hearing submissions before the AUC for which decisions have not been received. The outcome of these matters cannot be determined at this time.

4. TXU EUROPE SETTLEMENT

On November 19, 2002, an administration order was issued by an English Court against TXU Europe Energy Trading Limited ("TXU Europe") which had a long term "off take" agreement for 27.5% of the power produced by the 1,000 megawatt Barking generating plant in London, England, in which the Corporation, through Barking Power, has a 25.5% equity interest. Barking Power had filed a claim for damages for breach of contract related to TXU Europe's obligations to purchase 27.5% of the power produced by the Barking generating plant. Following negotiations with the administrators, an agreement was reached with respect to Barking Power's claim.

In settlement of its claim, Barking Power received distributions of £144.5 million (approximately $327 million) in 2005, of which the Corporation's share was $83.1 million, and distributions of £34.8 million (approximately $71 million) in 2006, of which the Corporation's share was $18.2 million. Income taxes of approximately $28.5 million relating to the distributions have been paid.

The Corporation's share of this settlement is being recognized in earnings in equal monthly amounts over the remaining term of the TXU Europe contract to September 30, 2010. Based on the foreign currency exchange rate in effect at December 31, 2008, earnings after income taxes of approximately $9.0 million per year have yet to be recognized. These earnings will be dependent upon foreign currency exchange rates in effect at the time that the earnings are recognized.

On May 31, 2007, £95.0 million of the TXU proceeds, of which the Corporation's share was $52.7 million, were applied to Barking Power's non-recourse long term debt.

5. INTEREST AND OTHER INCOME

	2008	2007
Interest	**$43.6**	$46.4
Allowance for funds used by regulated operations	**17.9**	9.7
Gains on dispositions of property, plant and equipment and other investments	**2.3**	3.2
Gain (loss) on natural gas purchase contracts derivative asset (Note 21)	**(12.4)**	13.5
Gain (loss) on power generation revenue contract liability (Note 21)	**9.6**	(9.4)
Cash flow hedge losses	**(4.8)**	(0.5)
Other	**2.9**	1.4
	$59.1	$64.3

6. INCOME TAXES

The income tax provision differs from that computed using the statutory tax rates for the following reasons:

	2008		2007	
Earnings before income taxes	**$579.9**	**%**	$498.7	%
Income taxes, at statutory rates	**$171.1**	**29.5**	$160.2	32.1
Part VI.1 tax (benefit)	**1.6**	**0.3**	(15.6)	(3.1)
Change in method of accounting for future income taxes in certain regulated operations	**-**	**-**	(34.4)	(6.9)
Unrecorded future income taxes relating to regulated operations	**(27.2)**	**(4.7)**	(4.9)	(1.0)
Change in future income taxes resulting from reduction in tax rates	**-**	**-**	(14.9)	(3.0)
Future income taxes recorded at less than current statutory rates	**(1.6)**	**(0.3)**	(3.6)	(0.7)
Foreign tax rate variance	**(1.5)**	**(0.3)**	(3.6)	(0.7)
Non-deductible interest on foreign financing	**1.4**	**0.2**	1.4	0.3
Tax reassessments	**(9.7)**	**(1.7)**	(8.8)	(1.8)
Other	**0.2**	**0.1**	1.9	0.4
	134.3	**23.1**	77.7	15.6
Current income taxes	**129.8**		112.6	
Future income tax (recoveries)	**$ 4.5**		$(34.9)	

6. INCOME TAXES (continued)

The future income tax liabilities (assets) comprise the following:

	2008	2007
Property, plant and equipment	$214.2	$185.2
Deferred assets and liabilities	(39.2)	(33.5)
Tax loss carryforwards	(19.0)	(0.6)
Derivative financial instruments	0.3	3.4
Other	2.3	1.0
	158.6	155.5
Less: Amounts included in current future income taxes	(5.9)	1.7
	$164.5	$153.8

At December 31, 2008, unrecorded future income tax liabilities of the regulated operations amounted to $192.2 million. The liabilities include $1.6 million in respect of Alberta Power (2000)'s generating plants, which will be recovered through future payments received in respect of the PPA's.

In 2008, the Corporation received a favorable tax decision from the Canada Revenue Agency ("CRA") with respect to ATCO Electric and ATCO Pipelines to treat certain previously reported capital outlays as current expenditures for tax purposes. As a result, the Corporation recognized a reduction in current income tax expense and an increase in interest income in respect of prior taxation years which resulted in an increase in earnings of $3.3 million.

In addition, the Corporation recognized a reduction in income tax expense of $2.6 million as a result of a favorable Tax Court of Canada decision to treat previously reported capital outlays incurred with respect to certain transformer costs as current expenditures for tax purposes. This amount was included in a regulatory deferral account to be refunded to customers and, therefore, did not impact 2008 earnings.

On May 22, 2008, the Federal Court of Appeal issued a decision overturning previous CRA reassessments pertaining to the computation of resource allowances and corresponding capital cost allowances for mining assets related to the Corporation's coal-fired power generation business. On July 8, 2008, the CRA advised that it would not seek leave to appeal to the Supreme Court of Canada in respect of this matter. This appeal and subsequent court decision applies to the 1997 to 1998 taxation years and allows ATCO Electric and Alberta Power (2000), as successor to ATCO Electric in the coal-fired generating plants, to claim additional resource allowance and capital cost allowance. This reduced current income tax expense and decreased interest expense which resulted in an increase to earnings of $3.0 million.

In 2007, the federal government announced an amendment to tax legislation pertaining to Part VI.1 tax (the tax payable on preferred share dividends paid by corporations). Prior to this change, corporations that had Part VI.1 tax payable were entitled to an income tax deduction equal to 9/4ths of the Part VI.1 tax payable. Effective January 1, 2003, this deduction was increased to three times the amount of the Part VI.1 tax payable. The CRA has been assessing corporate tax returns based on this proposed change being in effect since January 1, 2003, resulting in a reduction of taxes paid to the Canadian government. In the second quarter of 2007, the Corporation recorded a one-time reduction to current income tax expense which resulted in increased earnings of $15.6 million relating to years prior to 2007. Funds generated by operations increased by $15.6 million, offset by a similar reduction in changes in non-cash working capital, leaving the Corporation's cash position unchanged.

6. INCOME TAXES (continued)

In the fourth quarter of 2007, ATCO Gas successfully appealed previous CRA reassessments which resulted in an $8.8 million decrease in income taxes and an increase in interest income, net of income taxes, of $0.7 million for an overall increase to earnings of $9.5 million. These ATCO Gas CRA reassessments applied to the 1999 to 2006 taxation years and allowed ATCO Gas to treat previously reported capital outlays as current expenditures for income tax purposes.

There are tax loss carryforwards of $74.8 million for ATCO Power for which a tax benefit has been recorded. The losses are the result of a refiling of corporate tax returns that included a request to maximize previous years unclaimed capital cost allowances. Approximately one third of the losses begin to expire in 2010; with the remaining amounts expiring in 2014 and 2015.

There are tax loss carryforwards of $0.3 million for Canadian subsidiary corporations for which no benefit has been recorded. The losses for the Canadian subsidiary corporations begin to expire in 2015.

Income taxes paid amounted to $125.4 million (2007 — $135.6 million).

7. INVENTORIES

	2008	2007
Natural gas and fuel in storage	**$ 45.9**	$ 26.2
Raw materials and consumables	**63.0**	57.5
Finished goods	**0.4**	18.1
	$109.3	$101.8

For the unaudited three months ended December 31, 2008, the amount of inventories recognized as an expense was $26.0 million (2007 – $23.9 million). For the year ended December 31, 2008, the amount of inventories recognized as an expense was $98.9 million (2007 $97.4 million). There have been no write-downs to net realizable value and there have been $0.1 million reversals of previous write-downs to net realizable value.

Inventories in the amount of $23.9 million are pledged as security for liabilities.

8. PROPERTY, PLANT AND EQUIPMENT

		2008		2007	
	Composite Depreciation Rates	**Cost**	**Accumulated Depreciation**	Cost	Accumulated Depreciation
Utilities	3.6%	**$ 7,849.7**	**$2,767.2**	$ 7,036.4	$2,589.7
Power Generation	3.4%	**2,882.5**	**1,174.8**	2,839.9	1,093.9
Global Enterprises	9.7%	**378.7**	**182.1**	313.3	148.6
Other	11.2%	**30.1**	**7.8**	26.7	8.0
		$11,141.0	**4,131.9**	$10,216.3	3,840.2
Property, plant and equipment less accumulated depreciation			**7,009.1**		6,376.1
Unamortized contributions by utility customers for extensions to plant			**800.6**		697.6
			$6,208.5		$5,678.5

Accumulated depreciation includes amounts provided for future removal and site restoration costs, net of salvage value, of $461.2 million (2007 — $417.0 million).

Composite depreciation rates reflect total depreciation in the year as a percentage of mid-year cost, excluding construction work-in-progress of $433.2 million (2007 — $142.5 million) and non-depreciable assets of $45.7 million (2007 — $52.9 million).

9. OTHER ASSETS

	2008	2007
Accrued pension asset (Note 20)	**$133.4**	$139.5
Security deposits for debt	**17.8**	19.6
Long term receivable from joint venture	**7.3**	-
Other	**36.6**	35.2
	$195.1	$194.3

10. BANK INDEBTEDNESS AND LINES OF CREDIT

At December 31, 2008, bank indebtedness consists of $22.0 million repayable in Canadian dollars representing drawings on current credit facilities by ATCO Frontec. This facility bears interest equal to the 90 day banker's acceptance rate on advances, secured by a general assignment of assets of ATCO Frontec.

10. BANK INDEBTEDNESS AND LINES OF CREDIT (continued)

At December 31, 2008, the Corporation has the following lines of credit that enable it to obtain financing for general business purposes:

	2008			2007		
	Total	**Used**	**Available**	Total	Used	Available
Long term committed	**$ 326.0**	**$ 48.2**	**$277.8**	$ 326.0	$48.2	$277.8
Short term committed	**600.0**	**54.1**	**545.9**	600.0	10.0	590.0
Uncommitted	**99.1**	**28.1**	**71.0**	74.1	12.9	61.2
	$1,025.1	**$130.4**	**$894.7**	$1,000.1	$71.1	$929.0

Of the $130.4 million used (2007 – $71.1 million) at December 31, 2008, $47.0 million (2007 – $47.0 million) is included in long term debt, $22.0 million (2007 – nil) is included in bank indebtedness and $61.4 million (2007 – $24.1 million) represents outstanding letters of credit.

11. LONG TERM DEBT AND NON-RECOURSE LONG TERM DEBT

Long term debt

	Effective Interest Rate	**2008**	2007
Canadian Utilities			
CU Inc. debentures – unsecured			
2000 6.97% due June 2008	7.062%	**$ -**	$ 100.0
1989 Series 10.20% due November 2009	10.331%	**125.0**	125.0
1990 Series 11.40% due August 2010	11.537%	**125.0**	125.0
2000 7.05% due June 2011	7.130%	**100.0**	100.0
2007 4.883% due November 2012	4.990%	**35.0**	35.0
2004 5.096% due November 2014	5.162%	**100.0**	100.0
2002 6.145% due November 2017	6.217%	**150.0**	150.0
2004 5.432% due January 2019	5.492%	**180.0**	180.0
1999 6.8% due August 2019	6.861%	**300.0**	300.0
1990 Second Series 11.77% due November 2020	11.903%	**100.0**	100.0
2006 4.801% due November 2021	4.854%	**160.0**	160.0
1991 Series 9.92% due April 2022	10.063%	**125.0**	125.0
1992 Series 9.40% due May 2023	9.511%	**100.0**	100.0
2008 5.563% due May 2028	5.614%	**125.0**	-
2004 5.896% due November 2034	5.939%	**200.0**	200.0
2005 5.183% due November 2035	5.226%	**185.0**	185.0
2006 5.032% due November 2036	5.072%	**160.0**	160.0
2007 5.556% due October 2037	5.598%	**220.0**	220.0
2008 5.580% due May 2038	5.622%	**200.0**	-
CU Inc. other long term obligation, due June 2010, unsecured	4.750%	**4.5**	4.5
Canadian Utilities Limited debentures – unsecured			
2002 6.14% due November 2012	6.228%	**100.0**	100.0
Less: Deferred financing charges		**(15.0)**	(13.3)
		2,779.5	2,556.2

CU

11. LONG TERM DEBT AND NON-RECOURSE LONG TERM DEBT (continued)

***Long term debt** (continued)*

	Effective Interest Rate	2008	2007
ATCO Midstream Ltd. credit facility, at BA rates, due June 2013, unsecured [1]	Floating	**25.0**	25.0
ATCO Power Canada Ltd. credit facility, at BA rates, due August 2013, secured by a pledge of cash [1]	Floating	**22.0**	22.0
ATCO Frontec Ltd. credit facility, at Euribor rates, due October 2010: €20.8 million secured by a pledge of assets and certain contracts	Floating	**35.5**	-
		2,862.0	2,603.2
Less: Amounts due within one year		**17.7**	-
		$2,844.3	$2,603.2

On January 28, 2009, ATCO Power executed a credit facility agreement with the Commonwealth Bank of Australia to borrow AUD$100 million to fund the construction and operations of ATCO Power's new project located in Karratha, Western Australia. The new financing facility has a term that covers the project's construction period plus five years of operations. ATCO Power has swapped the variable interest rate in the facility to a fixed rate of 5.71% during the construction period and 6.16% during the operations period. The first draw under the facility in the amount of AUD$25 million occurred on January 30, 2009.

Non-recourse long term debt

Project Financing	Effective Interest Rate	2008	2007
Barking Power Limited payable in British pounds:			
Term loans, at fixed rates averaging 7.95%, due to 2010: (£12.5 million (2007 – £17.9 million))	7.95%	**$ 22.2**	$ 35.1
Term loan, at LIBOR, due to 2008 [1]: (2007 – £5.2 million)	Floating	-	10.2
Osborne Cogeneration Pty Ltd., payable in Australian dollars:			
Term loan, at Bank Bill rates, due to 2013 [1]: ($26.2 million AUD (2007 – $31.9 million AUD))	Floating [2]	**22.5**	27.7
ATCO Power Alberta Limited Partnership ("APALP"):			
Term loan, at LIBOR, due to 2014 [1]	Floating [2]	**49.4**	77.0
Joffre:			
Term loan, at BA rates, due to 2012 [1]	Floating [2]	**0.3**	0.4
Term facility, at Canadian Prime Advances, due to 2012 [1]	Floating [2]	**0.1**	0.1
Term loan, at LIBOR, due to 2012 [1]	Floating [2]	**0.7**	0.8
Notes, at fixed rate of 8.59%, due to 2020	8.845%	**32.0**	32.0
Scotford:			
Term loan, at BA rates, due to 2014 (1)	Floating [2]	**32.3**	42.5
Term facility, at Canadian Prime Advances, due to 2014 [1]	Floating [2]	**0.3**	10.7
Term loan, at LIBOR, due to 2014 [1]	Floating [2]	**8.2**	-
Notes, at fixed rate of 7.93%, due to 2022	8.302%	**24.4**	25.3

11. LONG TERM DEBT AND NON-RECOURSE LONG TERM DEBT (continued)

Non-recourse long term debt (continued)

Project Financing	Effective Interest Rate	2008	2007
Muskeg River:			
Term loan, at BA rates, due to 2014 [1]	Floating [2]	**26.0**	32.5
Term facility, at Canadian Prime Advances, due to 2014 [1]	Floating [2]	**0.1**	0.1
Term loan, at LIBOR, due to 2014 [1]	Floating [2]	**6.5**	8.1
Notes, at fixed rate of 7.56%, due to 2022	7.902%	**25.7**	27.6
Brighton Beach:			
Term loan, at BA rates, due to 2020 [1]	Floating [2]	**18.3**	19.2
Term loan, at LIBOR, due to 2020 [1]	Floating [2]	**16.4**	17.3
Construction overrun facility, at BA rates, due to 2020 [1]	Floating [2]	**4.5**	4.7
Construction overrun facility, at LIBOR, due to 2020 [1]	Floating [2]	**4.0**	4.3
Notes, at fixed rate of 6.924%, due to 2024	7.025%	**101.8**	104.9
Cory:			
Cost overrun facility, at BA rates, due to 2011 [1]	Floating [2]	**1.8**	2.4
Notes, at fixed rate of 7.586%, due to 2025	7.872%	**34.3**	35.5
Notes, at fixed rate of 7.601%, due to 2026	7.880%	**30.6**	31.5
Less: Deferred financing charges		**(5.2)**	(6.4)
		457.2	543.5
Less: Amounts due within one year		**44.8**	65.4
		$412.4	$478.1

BA – Bankers' Acceptance
LIBOR – London Interbank Offered Rate
Euribor – Euro Interbank Offered Rate

(1) *The above interest rates have additional margin fees at a weighted average rate of 1.2% (2007 — 1.2%). The margin fees are subject to escalation.*

(2) *Floating interest rates have been partially or completely hedged with interest rate swaps (see Note 21).*

The non-recourse long term debt is secured by charges on the projects' assets and by an assignment of the projects' bank accounts, outstanding contracts and agreements. The book value of the pledged assets and bank accounts at December 31, 2008 was $1,095.8 million (2007 — $1,235.6 million).

Guarantees

Canadian Utilities Limited has provided a number of guarantees related to ATCO Power's obligations under non-recourse loans associated with certain of its projects. These guarantees cover the following items:

a) **Construction liens** – Represents liens currently registered against project assets. Effective September 30, 2005, ATCO Power entered into an indemnity agreement with Brighton Beach Power Ltd. obligating it to cover any cash shortfalls associated with clearing the construction liens registered against the project. This agreement allowed the project to achieve financial completion under the terms of the project financing agreement. The maximum amount of the indemnity is $4.6 million. Canadian Utilities Limited issued a guarantee to Brighton Beach Power Ltd. guaranteeing the payments under the indemnity agreement. The indemnity and the guarantee are reduced as the liens are settled. At December 31, 2008, the value of the guarantee is $4.6 million. Subsequent to year

end, all remaining disputes for this project were settled, and consequently, this guarantee will be removed in the first quarter of 2009.

b) **Project cash flows** — Represents annual payments related to maintaining base case margins for electricity prices on the merchant power component of the project, being 24 megawatts ("MW") for the Scotford project and 48 MW for the Muskeg River project. These guarantees became effective upon the commercial operation of the plants and exist until 2022, when the project debt is to be fully repaid. The amounts payable under these guarantees will vary each year depending on the pool price received for the merchant power generated. Any payments made to maintain the project base case margins will either be available for distribution to the owners or be applied to mandatory prepayment of the project debt in accordance with the terms of the project financing agreement depending upon the specific operating results of the plant. At December 31, 2008, no amounts were outstanding under the guarantee.

c) **Reserve amounts** — Represents amounts to be set aside for major maintenance and debt service reserves as stipulated in the project's financing agreement. These reserves are intended to be funded with project cash flows. To the extent that project cash flows are insufficient to meet reserve requirements, Canadian Utilities Limited may choose to provide guarantees in lieu of ATCO Power providing security. At December 31, 2008, the amount of the obligations under these guarantees is:

Project	Major Maintenance	Debt Service
APALP project financing	Nil [(1)]	$6.8
Brighton Beach project financing	Nil [(2)]	Nil
Cory project financing	Nil [(1)]	Nil
Joffre project financing	Nil [(3)]	$1.5
Muskeg River project financing	Nil [(1)]	$5.0
Scotford project financing	Nil [(1)]	$5.4

(1) *No major maintenance reserve required for this financing.*
(2) *Reserve requirements of $0.2 million met with project cash flows.*
(3) *Reserve requirements of $0.5 million met with project cash flows.*

d) **Prepaid operating and maintenance fee** — Should ATCO Power cease to be operator of the APALP generating plants as a result of a termination of the operating agreement, Canadian Utilities Limited has guaranteed the payment of the unamortized portion of the prepaid operating and maintenance fee to APALP, the proceeds of which are to be used to repay project debt in accordance with the project financing agreements. This guarantee, which declines by $1.2 million per year, remains in effect until 2016, when the project debt is to be fully repaid. At December 31, 2008, the maximum value of the guarantee is $27.6 million.

e) **Purchase project assets** — Represents an obligation to purchase the Scotford and Muskeg River projects at a price sufficient to repay any outstanding project debt upon the occurrence of any one of the following very limited events:

(i) where all of the following events have occurred:
- the insolvency of ATCO Power;
- the failure of the project debt lenders to complete a sale of the project pursuant to their security within a fixed period of time; and
- the project purchaser of electricity and steam elects to terminate its purchase contracts due to the insolvency of ATCO Power;

11. LONG TERM DEBT AND NON-RECOURSE LONG TERM DEBT (continued)

(ii) where the project purchaser of electricity and steam does not remove ATCO Power as operator of the project after an event of default under the project financing agreements in circumstances where such default is either:

- a deliberate or willful breach of a project financing agreement; or
- where ATCO Power has failed to co-operate with the lenders in a sale of the project; and

(iii) where the project purchaser of electricity and steam terminates its purchase contracts for the project as a result of a default by ATCO Power's project minority joint venturers. ATCO Power has the right to cure any such default by acquiring the minority interest which is in default.

These guarantees remain in effect until the project debt is fully repaid. At December 31, 2008, no such events have occurred.

Canadian Utilities Limited has also guaranteed ATCO Power's duties to operate the Barking Power, Scotford and Muskeg River generating plants in accordance with acceptable industry operating standards. The guarantees to operate Barking Power, Scotford and Muskeg expire on September 30, 2010, December 1, 2009 and January 1, 2009, respectively.

ATCO Power (80%) and ATCO Resources (20%), a wholly owned subsidiary of Canadian Utilities Limited's parent corporation, ATCO Ltd., have a joint venture in the above projects subject to guarantees, excluding Barking Power.

The foregoing guaranteed amounts represent ATCO Power's 80% interest. Canadian Utilities Limited has also guaranteed similar obligations in respect of ATCO Resources' 20% interest. ATCO Ltd. has indemnified and agreed to reimburse Canadian Utilities Limited for any amounts it may be required to pay under these guarantees in respect of ATCO Resources' 20% interest.

To date, Canadian Utilities Limited has not been required to pay any of its guaranteed obligations.

Contractual maturities of debt

The undiscounted contractual maturities of long term debt and non-recourse long term debt are as follows:

	Long Term Debt		Non-Recourse Long Term Debt		Total	
	Principal	Interest[1]	Principal	Interest[1]	Principal	Interest[1]
2009	$ 142.7	$ 190.6	$ 44.8	$ 30.3	$ 187.5	$ 220.9
2010	147.3	176.8	49.1	26.8	196.4	203.6
2011	100.0	158.3	42.3	23.4	142.3	181.7
2012	135.0	154.7	39.9	20.8	174.9	175.5
2013	47.0	146.8	42.3	18.4	89.3	165.2
2014 and thereafter	2,305.0	1,819.0	244.0	86.4	2,549.0	1,905.4
	$2,877.0	$2,646.2	$462.4	$206.1	$3,339.4	$2,852.3

(1) *Interest payments on floating rate debt that has not been hedged have been estimated using rates in effect at December 31, 2008. Interest payments on debt that has been hedged have been estimated using the hedged rates.*

Of the $187.5 million due in 2008, $125.0 million is to be refinanced and is, therefore, excluded from long term debt due within one year in the balance sheet.

11. LONG TERM DEBT AND NON-RECOURSE LONG TERM DEBT (continued)

Interest expense

Interest expense is as follows:

	2008	2007
Long term debt	**$186.3**	$169.1
Non-recourse long term debt	**36.8**	43.2
Bank indebtedness	**7.2**	1.4
Amortization of deferred financing charges	**3.2**	3.7
	$233.5	$217.4

Interest paid amounted to $226.7 million (2007 — $210.6 million).

12. DEFERRED CREDITS

	2008	2007
Accrued other post employment benefits liability (Note 20)	**$ 58.5**	$ 52.8
Deferred availability incentives	**61.3**	41.8
Asset retirement obligations	**77.7**	73.1
Power generation revenue contract liability (Note 21)	**44.6**	54.2
Liability to customers for refund of future income taxes (Note 3)	**19.2**	25.8
Deferred revenues (Note 4)	**12.2**	26.2
Accrued equipment repairs and maintenance	**5.0**	8.6
Other	**23.4**	25.4
	$301.9	$307.9

Deferred availability incentives

Amortization of deferred availability incentives, which was recorded in revenues, amounted to $12.6 million (2007 – $11.8 million).

The amount to be amortized is dependent upon estimates of future generating unit availability and future electricity prices over the term of the PPA's. Each quarter, the Corporation uses these estimates to forecast the incentives to be received from, less penalties to be paid to, the PPA counterparties. These forecasts are added to the accumulated unamortized deferred availability incentives outstanding at the end of the quarter; the resulting total is divided by the remaining term of the PPA to arrive at the amortization for the quarter.

Asset retirement obligations

Changes in asset retirement obligations are summarized below:

	2008	2007
Obligations at beginning of year	**$73.1**	$69.4
Obligations incurred	**1.0**	0.1
Accretion expense	**3.6**	3.6
Obligations at end of year	**$77.7**	$73.1

12. DEFERRED CREDITS (continued)

The Corporation estimates the undiscounted amount of cash flow required to settle the asset retirement obligations is approximately $134 million, which will be incurred between 2009 and 2052. The discount rates used to calculate the fair value of the asset retirement obligations have a weighted average rate of 5.7%.

13. EQUITY PREFERRED SHARES

CU Inc. equity preferred shares

Authorized and issued

Authorized: An unlimited number of Series Preferred Shares, issuable in series.

Issued:

	Stated Value	Redemption Dates	**2008**		2007	
			Shares	**Amount**	Shares	Amount
	(dollars)					
Cumulative Redeemable Preferred Shares						
4.60% Series 1	$25.00	See below	**4,600,000**	**$115.0**	4,600,000	$115.0

On April 18, 2007, CU Inc., a subsidiary corporation, issued $115.0 million Cumulative Redeemable Preferred Shares Series 1 at a price of $25.00 per share for cash. The dividend rate has been fixed at 4.60%. The net proceeds of the issue were used in part to redeem $91.8 million of the outstanding Cumulative Redeemable Second Preferred Shares Series Q, R and S of ATCO Electric and ATCO Gas and Pipelines, subsidiary corporations of CU Inc., that are held by Canadian Utilities Limited.

Fair values

Fair values for preferred shares determined using quoted market prices for the same or similar issues are $67.2 million (2007 - $94.7 million).

Redemption privileges

The Series 1 preferred shares are redeemable at the option of the Corporation commencing on June 1, 2012, at the stated value plus a 4% premium per share for the next 12 months plus accrued and unpaid dividends. The redemption premium declines by 1% in each succeeding twelve month period until June 1, 2016.

13. EQUITY PREFERRED SHARES (continued)

Canadian Utilities Limited equity preferred shares

Authorized and issued

Authorized: An unlimited number of Series Second Preferred Shares, issuable in series.

Issued:

	Stated Value (dollars)	Redemption Dates	2008 Shares	2008 Amount	2007 Shares	2007 Amount
Cumulative Redeemable Second Preferred Shares						
5.8% Series W	$25.00	See below	**6,000,000**	**$150.0**	6,000,000	$150.0
6.0% Series X	$25.00	See below	**6,000,000**	**150.0**	6,000,000	150.0
Perpetual Cumulative Second Preferred Shares						
4.35% Series O	$25.00	December 2, 2011	**1,600,000**	**40.0**	1,600,000	40.0
4.35% Series T	$25.00	December 2, 2011	**1,600,000**	**40.0**	1,600,000	40.0
4.35% Series U	$25.00	December 2, 2011	**800,000**	**20.0**	800,000	20.0
4.70% Series V	$25.00	October 3, 2012	**4,400,000**	**110.0**	4,400,000	110.0
				$510.0		$510.0
Total CU Inc. and Canadian Utilities Limited equity preferred shares				**$625.0**		$625.0

On May 18, 2007, Canadian Utilities Limited redeemed $126.5 million of outstanding Cumulative Redeemable Second Preferred Shares Series Q, R, and S at a price of $25.00 per share plus accrued and unpaid dividends per share.

The dividends payable on the Series O, T, U, and V preferred shares are fixed until the redemption dates specified above, at which time a new dividend rate may be established by negotiations between Canadian Utilities Limited and the owners of the shares.

On October 3, 2007, the dividend rate on the Series V preferred shares was reset from 5.25% to 4.70%.

Fair values

Fair values for preferred shares determined using quoted market prices for the same or similar issues are $456.3 million (2007 — $517.3 million).

Redemption privileges

The preferred shares, except for Series W and X, are redeemable on the dates specified above at the option of Canadian Utilities Limited at the stated value plus accrued and unpaid dividends.

The Series W preferred shares are redeemable commencing on March 1, 2008 at the stated value plus a 4% premium for the next 12 months plus accrued and unpaid dividends. The redemption premium declines by 1% in each succeeding 12 month period until March 1, 2012.

The Series X preferred shares are redeemable commencing June 1, 2008 at the stated value plus a 4% premium for the next 12 months plus accrued and unpaid dividends. The redemption premium declines by 1% in each succeeding 12 month period until June 1, 2012.

14. CLASS A AND CLASS B SHARES

Authorized and issued

	Class A Non-Voting		Class B Common		Total	
	Shares	Amount	Shares	Amount	Shares	Amount
Authorized:	Unlimited		Unlimited			
Issued and outstanding:						
December 31, 2006	81,456,686	$376.9	43,931,484	$139.1	125,388,170	$516.0
Purchased and cancelled	(157,800)	(0.7)	-	-	(157,800)	(0.7)
Stock options exercised	64,300	1.6	-	-	64,300	1.6
Converted: Class B to Class A	145,800	0.5	(145,800)	(0.5)	-	-
December 31, 2007	**81,508,986**	**$378.3**	**43,785,684**	**$138.6**	**125,294,670**	**$516.9**
Stock options exercised	**215,450**	**5.0**	**-**	**-**	**215,450**	**5.0**
Converted: Class B to Class A	**1,798,558**	**5.7**	**(1,798,558)**	**(5.7)**	**-**	**-**
December 31, 2008	**83,522,994**	**$389.0**	**41,987,126**	**$132.9**	**125,510,120**	**$521.9**

From January 1, 2009 to February 13, 2009, no stock options were granted or cancelled, 4,700 stock options were exercised and 230,200 Class B common shares were converted to Class A non-voting shares.

Earnings per share

Earnings per Class A non-voting and Class B common share is calculated by dividing the earnings attributable to Class A and Class B shares by the weighted average shares outstanding. Diluted earnings per share is calculated using the treasury stock method, which reflects the potential exercise of stock options on the weighted average Class A non-voting and Class B common shares outstanding. The average number of shares used to calculate earnings per share are as follows:

	Three Months Ended December 31		Year Ended December 31	
	2008	2007	**2008**	2007
Weighted average shares outstanding	**125,507,489**	125,390,562	**125,407,951**	125,409,080
Effect of dilutive stock options	**338,936**	564,511	**376,466**	525,057
Weighted average dilutive shares outstanding	**125,846,425**	125,955,073	**125,784,417**	125,934,137

Share owner rights

The owners of the Class A non-voting shares and the Class B common shares are entitled to share equally, on a share for share basis, in all dividends declared by Canadian Utilities Limited on either of such classes of shares as well as the remaining property of Canadian Utilities Limited upon dissolution. The owners of the Class B common shares are entitled to vote and to exchange at any time each share held for one Class A non-voting share.

14. CLASS A AND CLASS B SHARES (continued)

If a take-over bid is made for the Class B common shares which would result in the offeror owning more than 50% of the outstanding Class B common shares and which would constitute a change in control of Canadian Utilities Limited, owners of Class A non-voting shares are entitled, for the duration of the bid, to exchange their Class A non-voting shares for Class B common shares and to tender such Class B common shares pursuant to the terms of the take-over bid. Such right of exchange is conditional upon the completion of the take-over bid giving rise to the right of exchange, and if the take-over bid is not completed, then the right of exchange shall be deemed never to have existed. In addition, owners of the Class A non-voting shares are entitled to exchange their shares for Class B common shares of Canadian Utilities Limited if ATCO Ltd., the present controlling share owner of Canadian Utilities Limited, ceases to own or control, directly or indirectly, more than 10,000,000 of the issued and outstanding Class B common shares of Canadian Utilities Limited. In either case, each Class A non-voting share is exchangeable for one Class B common share, subject to changes in the exchange ratio for certain events such as a stock split or rights offering.

Normal course issuer bid

On May 23, 2007, Canadian Utilities Limited commenced a normal course issuer bid for the purchase of up to 5% of the outstanding Class A shares. The bid expired on May 22, 2008. From May 23, 2007, to May 22, 2008, 157,800 shares were purchased, all of which were purchased in 2007. On May 23, 2008, Canadian Utilities commenced a new normal course issuer bid for the purchase of up to 3% of the outstanding Class A shares. The bid will expire on May 22, 2009. No shares have been purchased from May 23, 2008 to February 13, 2009.

15. CAPITAL DISCLOSURES

The Corporation's objectives when managing capital are:

1. to safeguard the ability to continue as a going concern, so that it can continue to provide returns to share owners and benefits for other stakeholders;
2. to maintain an appropriate credit rating in order to provide efficient and cost effective access to funds required for operations and growth; and
3. to remain within the capital structure approved by the AUC.

The Corporation includes share owners' equity, equity preferred shares, long term debt and non-recourse long term debt in its determination of capitalization. In managing its capital, the Corporation considers both the regulated and non-regulated operations in the consolidated group as well as changes in economic conditions and risks impacting the core assets and operations. In maintaining or adjusting its capital structure, the Corporation may adjust the amount of dividends paid to share owners, issue or purchase Class A and Class B shares, and issue or redeem equity preferred shares, long term debt and non-recourse long term debt.

The Corporation's utility operations are regulated primarily by the AUC, which, through the generic cost of capital decision issued in 2004, established the capital structure for each utility. The utility operations are, therefore, capitalized consistent with the generic cost of capital decision. The capitalization involves the use of long term debt and preferred share financings; the AUC approved the continued use of the latter in a decision issued in 2006.

While the Corporation's utility operations are capitalized consistent with the AUC decisions, the Corporation itself is not restricted in its capital structure. The capital structure for the Corporation is set

15. CAPITAL DISCLOSURES (continued)

relative to risk and to meet the financial and operational objectives of the Corporation (while considering the decisions of the regulator).

Decisions on the level and type of financing are based on assessments by management in line with the Corporation's objectives. In determining the type of financing to be undertaken by a given operation, the Corporation has a goal of managing the financial risk to the Corporation as a whole.

Capital is monitored through an equity capitalization measure which is calculated as total equity divided by total capitalization. Total equity is comprised of Class A and Class B shares, contributed surplus, retained earnings, accumulated other comprehensive income and equity preferred shares. Total capitalization is comprised of long term debt, non-recourse long term debt and total equity. The Corporation's strategy, which is unchanged from 2007, is to maintain the equity capitalization allowed by the regulator for the regulated operations and to structure the non-regulated operations so as to sustain access to cost effective financing by maintaining high credit ratings on debt and preferred shares. The Corporation looks to maintain an equity capitalization in the range of 45% to 55%.

Other measures that are taken into consideration are interest coverage and interest and preferred dividend coverage. Interest coverage is calculated by dividing earnings before income taxes, interest expense and dividends on equity preferred shares by total interest expense. Interest and preferred dividend coverage is calculated by dividing earnings before income taxes, interest expense and dividends on equity preferred shares by interest expense and dividends on equity preferred shares (grossed up to pre-tax equivalents). The Corporation looks to maintain interest coverage of at least 2.5 and interest and preferred dividend coverage of at least 2.0; these objectives are unchanged from 2007.

Equity capitalization, interest coverage and interest and preferred dividend coverage do not have any standardized meaning under GAAP and might not be comparable to similar measures presented by other companies.

The Corporation's key measures of capital structure are as follows:

	2008	2007
Class A and Class B shares	**$ 521.9**	$ 516.9
Contributed surplus	**2.6**	1.9
Retained earnings	**2,282.3**	2,036.0
Accumulated other comprehensive income	**(55.1)**	(33.1)
Equity preferred shares	**625.0**	625.0
Total equity	**3,376.7**	3,146.7
Long term debt	**2,844.3**	2,603.2
Non-recourse long term debt	**412.4**	478.1
Total debt	**3,256.7**	3,081.3
Total capitalization	**$6,633.4**	$6,228.0
Equity capitalization	**51%**	51%

The equity capitalization is consistent with the Corporation's objectives. Total equity increased primarily due to higher earnings of the Corporation reflected in increased retained earnings and higher Class A and Class B shares due to the exercise of stock options offset by decreased accumulated other comprehensive income resulting from the impact of foreign currency translation of self-sustaining foreign operations.

15. CAPITAL DISCLOSURES (continued)

Total debt increased primarily due to financings for utility capital expenditures and ATCO Frontec's European operations partially offset by redemptions of long term debt and non-recourse long term debt.

	2008	2007
Interest coverage [1]	**3.5**	3.3
Interest and preferred dividend coverage [1]	**2.9**	2.7

(1) *The coverage ratios for 2007 were negatively impacted by the AUC decision that directed ATCO Electric to refund future income taxes to customers. The total reduction in revenues and income taxes recorded in 2007 was $39.6 million. If the reduction in revenues had not occurred, interest coverage would have been 3.5 and interest and preferred dividend coverage would have been 2.8.*

For the year ended December 31, 2008, the Corporation was in compliance with externally imposed requirements on its capital (including debt covenants). The Corporation has a number of regulatory filings and regulatory hearing submissions before the AUC for which decisions have not been received, the outcome of which could affect the capital structure of the Corporation.

16. STOCK BASED COMPENSATION PLANS

Stock option plan

Of the 6,400,000 Class A non-voting shares authorized for grant in respect of options under Canadian Utilities Limited's stock option plan, 2,972,700 Class A non-voting shares are available for issuance at December 31, 2008. Options may be granted to directors, officers and key employees of Canadian Utilities Limited and its subsidiaries at an exercise price equal to the weighted average of the trading price of the shares on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant. The vesting provisions and exercise period (which cannot exceed 10 years) are determined at the time of grant.

Changes in shares under option are summarized below:

	2008		2007	
	Class A Shares	**Weighted Average Exercise Price**	Class A Shares	Weighted Average Exercise Price
Options at beginning of year	**1,304,200**	**$28.02**	1,208,000	$25.12
Granted	**149,500**	**44.38**	163,500	47.82
Exercised	**(215,450)**	**23.09**	(64,300)	22.91
Cancelled	**-**	**-**	(3,000)	47.84
Options at end of year	**1,238,250**	**$30.86**	1,304,200	$28.02

16. STOCK BASED COMPENSATION PLANS (continued)

Information about stock options outstanding at December 31, 2008 is summarized below:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Class A Shares	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Class A Shares	Weighted Average Exercise Price
$17.23 - $18.87	330,050	0.9	$17.86	330,050	$17.86
$20.65 - $28.65	273,200	2.6	23.88	272,000	23.87
$30.25 - $47.84	635,000	7.5	40.61	202,900	36.33
$17.23 - $47.84	1,238,250	4.6	$30.86	804,950	$24.55

In 2008, Canadian Utilities Limited granted 149,500 options to purchase Class A non-voting shares at a weighted average exercise price of $44.38 per share. The options have a term of ten years and vest over the first five years.

Changes in contributed surplus are summarized below:

	2008	2007
Contributed surplus at beginning of year	**$1.9**	$1.2
Stock option expense	**0.9**	0.7
Mid-term incentive plan purchases	**(0.2)**	-
Contributed surplus at end of year	**$2.6**	$1.9

The Corporation uses the Black-Scholes option pricing model, which estimated the weighted average fair value of the options granted during 2008 at $6.71 per option (2007 — $7.23 per option) using the following weighted average assumptions:

	2008	2007
Risk free interest rate	**3.2%**	4.0%
Expected holding period prior to exercise	**6.6 years**	6.2 years
Share price volatility	**18.8%**	12.5%
Estimated annual Class A share dividend	**3.0%**	2.5%

Share appreciation rights

Directors, officers and key employees of the Corporation may be granted share appreciation rights that are based on Class A non-voting shares of Canadian Utilities Limited or Class I Non-Voting Shares of ATCO Ltd. The vesting provisions and exercise period (which cannot exceed 10 years) are determined at the time of grant. The base value of the share appreciation rights is equal to the weighted average of the trading price of the Class A non-voting shares and the Class I Non-Voting Shares, respectively, on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant. The holder is entitled on exercise to receive a cash payment equal to any increase in the market price of the Class A non-voting shares and Class I Non-Voting Shares, respectively, over the base value of the share appreciation rights exercised.

Share appreciation rights income amounted to $2.0 million (2007 — $0.7 million expense).

16. STOCK BASED COMPENSATION PLANS (continued)

Mid-term incentive plan

During the year, the Corporation implemented a mid-term incentive plan ("MTIP") whereby officers and key employees of the Corporation may be awarded rights to receive Class A non-voting shares of Canadian Utilities Limited. The awards vest after a period of three years and are settled with shares purchased on the secondary market. The Corporation, through an independent trustee, has purchased $0.2 million of shares to be distributed to employees upon vesting of awards. The cost of the purchase of the shares has been deducted from contributed surplus. Compensation expense related to MTIP grants amounted to less than $0.1 million during the year with a corresponding charge to contributed surplus.

17. CHANGES IN NON-CASH WORKING CAPITAL

	2008	2007
Operating activities, changes related to:		
Accounts receivable	**$(14.8)**	$(15.8)
Inventories	**(8.2)**	(3.8)
Regulatory assets	**(12.4)**	(14.7)
Prepaid expenses	**(0.4)**	(5.2)
Accounts payable and accrued liabilities	**9.1**	35.4
Income taxes payable	**2.0**	(20.3)
Regulatory liabilities	**11.9**	5.4
	$(12.8)	$(19.0)
Investing activities, changes related to:		
Inventories	**$ (1.7)**	$ (2.9)
Prepaid expenses	**1.6**	(1.1)
Accounts payable and accrued liabilities	**37.5**	16.3
	$ 37.4	$ 12.3
Financing activities, changes related to:		
Accounts receivable	**$ (0.1)**	$ -

18. JOINT VENTURES

The Corporation's interest in joint ventures is summarized below:

	2008	2007
Statement of earnings		
Revenues	**$ 609.4**	$ 484.9
Operating expenses	**378.1**	291.0
Depreciation and amortization	**46.9**	42.1
Interest	**31.1**	36.1
	153.3	115.7
Interest and other income	**2.0**	13.3
Earnings from joint ventures before income taxes	**$ 155.3**	$ 129.0
Balance sheet		
Current assets	**$ 191.2**	$ 165.7
Current liabilities	**(165.9)**	(142.6)
Property, plant and equipment	**837.4**	871.7
Deferred items – net	**(42.7)**	(50.1)
Non-recourse long term debt	**(318.4)**	(350.4)
Investment in joint ventures	**$ 501.6**	$ 494.3
Statement of cash flows		
Operating activities	**$ 185.8**	$ 143.6
Investing activities	**(30.3)**	(17.7)
Financing activities	**(149.7)**	(208.0)
Foreign currency translation	**(2.7)**	(10.7)
Increase (decrease) in cash position	**$ 3.1**	$ (92.8)

Current assets include cash of $70.3 million (2007 — $65.2 million) which is only available for use within the joint ventures.

19. RELATED PARTY TRANSACTIONS

In transactions with ATCO Ltd. and its wholly owned subsidiary corporations, the Corporation sold fuel in the amount of $2.6 million (2007 — $2.0 million), provided computer operations and systems development services totaling $14.1 million (2007 – $6.7 million), recovered administrative expenses totaling $1.5 million (2007 — $1.6 million) and incurred administrative expenses and corporate signature rights totaling $8.9 million (2007 — $8.3 million). The Corporation also incurred capital expenditures of $10.3 million (2007 — $9.4 million) that were recorded in property, plant and equipment.

In transactions with entities related through common control, the Corporation provided security services and recovered administrative expenses totaling nil (2007 – $0.3 million) and incurred advertising, promotion and administrative expenses totaling $1.4 million (2007 — $1.5 million).

At December 31, 2008, accounts receivable due from related parties amounted to $3.3 million (2007 – $0.8 million) and accounts payable due to related parties amounted to $6.6 million (2007 – $8.3 million).

These transactions are in the normal course of business and under normal commercial terms.

20. EMPLOYEE FUTURE BENEFITS

The Corporation maintains registered defined benefit and defined contribution pension plans for most of its employees and provides other post employment benefits, principally health, dental and life insurance, for retirees and their dependants. The defined benefit pension plans provide for pensions based on employees' length of service and final average earnings. As of 1997, new employees automatically participate in the defined contribution pension plan and employees participating in the defined benefit pension plans may transfer to the defined contribution pension plan at any time. Upon transfer, further accumulation of benefits under the defined benefit pension plans ceases. The Corporation also maintains non-registered, non-funded defined benefit pension plans for certain officers and key employees.

In June 2008, the Corporation prospectively changed the method of apportioning the costs of OPEB plans to individual subsidiaries. Formerly, each subsidiary was apportioned a percentage of its payroll costs at a rate calculated for the plan as a whole. The revised method determines the accrued OPEB liabilities and costs on a company-by-company basis. Under the new method of allocation, the OPEB liability and non-current regulatory assets for the regulated subsidiaries, excluding Alberta Power (2000), increased by \$10.4 million ("Adjustment to beginning liability"). Pursuant to an AUC decision effective January 1, 2000, the regulated operations, excluding Alberta Power (2000), are required to expense contributions for other post employment benefit plans as paid. Consequently, there was no change in their earnings for the unaudited three months and year ended December 31, 2008. The difference between the amounts accrued and paid is deferred in non-current regulatory assets.

The OPEB liability for Alberta Power (2000) and the non-regulated subsidiaries decreased which resulted in an increase to earnings of \$7.0 million, of which \$5.5 million was recorded in the second quarter of 2008 and \$1.5 million was recorded in the fourth quarter of 2008.

20. EMPLOYEE FUTURE BENEFITS (continued)

Information about the Corporation's benefit plans, in aggregate, is as follows:

	2008		2007	
	Pension Benefit Plans	**Other Post Employment Benefit Plans**	Pension Benefit Plans	Other Post Employment Benefit Plans
Benefit plan assets, obligations and funded status				
Market value of plan assets:				
Beginning of year	**$1,688.6**	**$ -**	$1,704.1	$ -
Actual return on plan assets	**(236.4)**	**-**	30.7	-
Employee contributions	**3.6**	**-**	3.8	-
Employer contributions	**1.0**	**-**	0.7	-
Benefit payments	**(45.5)**	**-**	(41.2)	-
Payments to defined contribution plans [(1)]	**(12.2)**	**-**	(9.5)	-
End of year	**$1,399.1**	**$ -**	$1,688.6	$ -
Accrued benefit obligations:				
Beginning of year	**$1,650.7**	**$ 79.4**	$1,642.0	$ 83.5
Current service cost	**37.1**	**2.1**	39.8	2.6
Interest cost	**91.8**	**3.8**	86.3	4.2
Employee contributions	**3.6**	**-**	3.8	-
Benefit payments from plán assets [(2)]	**(45.5)**	**-**	(41.2)	-
Benefit payments by employer	**(4.5)**	**(2.1)**	(4.3)	(2.0)
Experience gains [(3)]	**(333.6)**	**(25.4)**	(75.7)	(8.9)
End of year [(4)]	**$1,399.6**	**$ 57.8**	$1,650.7	$ 79.4
Funded status:				
Excess (deficiency) of assets over obligations [(4)]	**$ (0.5)**	**$(57.8)**	$ 37.9	$ (79.4)
Amounts not yet recognized in financial statements:				
Unrecognized net cumulative experience losses on plan assets and accrued benefit obligations	**287.4**	**(17.2)**	289.1	8.2
Unrecognized net transitional liability (asset)	**(153.5)**	**16.5**	(187.5)	18.4
Accrued asset (liability) (Notes 9, 12)	**$ 133.4**	**$(58.5)**	$ 139.5	$ (52.8)
Regulatory asset (liability) [(5)] (Note 2)	**$ (110.2)**	**$ 46.9**	$ (110.0)	$ 32.3

(1) *Employer contributions for certain of the Corporation's defined contribution pension plans are paid from the assets of the defined benefit pension plans.*

(2) *Pension plan benefit payments are indexed to increases in the Canadian Consumer Price Index to a maximum increase of 3% per annum.*

(3) *An increase in the liability discount rate at December 31 assumption resulted in the experience gains in 2008 (2007 – a change in the liability discount rate resulted in experience gains of approximately $99 million, whereas a change in the average compensation rate increase assumption for the year resulted in experience losses of approximately $29 million for the pension benefit plans).*

(4) *The non-registered, non-funded defined benefit pension plans accrued benefit obligations decreased to $74.1 million at December 31, 2008 (2007 – $84.0 million) due to an increase in the liability discount rate. Apart from these obligations, the excess of assets over obligations for the registered defined benefit pension plans at December 31, 2008 was $73.6 million (2007 – $121.9 million).*

(5) *The regulatory asset (liability) reflects an AUC decision to record costs of employee future benefits in the regulated operations, excluding Alberta Power (2000), when paid rather than accrued.*

20. EMPLOYEE FUTURE BENEFITS (continued)

	2008		2007	
	Pension Benefit Plans	**Other Post Employment Benefit Plans**	Pension Benefit Plans	Other Post Employment Benefit Plans
Benefit plan cost				
Components of benefit plan cost:				
Current service cost	**$ 37.1**	**$ 2.1**	$ 39.8	$ 2.6
Interest cost	**91.8**	**3.8**	86.3	4.2
Actual return on plan assets	**236.4**	**-**	(30.7)	-
Experience gains on accrued benefit obligations	**(333.6)**	**(25.4)**	(75.7)	(8.9)
	31.7	**(19.5)**	19.7	(2.1)
Adjustments to recognize long term nature of employee future benefits:				
Unrecognized portion of actual return on plan assets	**(343.6)**	**-**	(64.4)	-
Unrecognized portion of experience gains on accrued benefit obligations	**333.6**	**25.4**	75.7	8.9
Amortization of net cumulative experience losses on plan assets and accrued benefit obligations	**11.7**	**-**	15.6	0.6
Amortization of net transitional liability (asset)	**(34.0)**	**1.9**	(33.5)	2.3
	(32.3)	**27.3**	(6.6)	11.8
Defined benefit plans cost (income)	**(0.6)**	**7.8**	13.1	9.7
Defined contribution plans cost	**14.1**	**-**	11.0	-
Adjustment to beginning liability	**-**	**(10.4)**	-	-
Total cost (income)	**13.5**	**(2.6)**	24.1	9.7
Less: Capitalized	**2.0**	**2.5**	2.1	2.5
Less: Unrecognized defined benefit plans cost (income) (1) (2)	**(0.9)**	**2.4**	7.8	2.9
Net cost (income) recognized (2)	**$ 12.4**	**$ (7.5)**	$ 14.2	$ 4.3

(1) The unrecognized defined benefit plans cost (income) reflects an AUC decision to record costs of employee future benefits in the regulated operations, excluding Alberta Power (2000), when paid rather than accrued.

(2) Net cost recognized for pension benefit plans in 2008 includes the amortization of \$3.4 million (2007 – \$2.6 million) of the deferred pension assets recorded by the Corporation upon the adoption of the current accounting standard in 2000. On October 11, 2006, the AUC approved recovery of these assets for a nine-year period commencing January 1, 2005 (Note 2).

In the unaudited three months ended December 31, 2008, net cost of \$3.6 million (2007 – \$3.0 million) was recognized for pension benefit plans and net income of \$1.5 million (2007 – net expense of \$1.0 million) was recognized for other post employment benefit plans.

20. EMPLOYEE FUTURE BENEFITS (continued)

Weighted average assumptions

	2008		2007	
	Pension Benefit Plans	**Other Post Employment Benefit Plans**	Pension Benefit Plans	Other Post Employment Benefit Plans
Assumptions regarding benefit plan cost:				
Expected long term rate of return on plan assets for the year	**7.0%**	**-**	6.6%	-
Liability discount rate for the year	**5.5%**	**5.5%**	5.1%	5.1%
Average compensation increase for the year	**(1)**	**-**	(1)	-
Assumptions regarding accrued benefit obligations:				
Liability discount rate at December 31	**7.0%**	**7.0%**	5.5%	5.5%
Long term inflation rate	**2.5%**	**(2)**	2.5%	(2)

(1) *The assumed average compensation increases are 4.0% for five years (2008-2012) and 3.5% thereafter.*

(2) *The assumed annual health care cost trend rate increases used in measuring the accumulated post employment benefit obligation are as follows: for drug costs, 7.2% for 2008 grading down over 5 years to 4.5% (2007 – 7.8% grading down over 6 years to 4.5%), and, for other medical and dental costs, 4.0% for 2008 and thereafter (2007 – 4.0% for 2007 and thereafter).*

The sensitivities of key assumptions used in measuring accrued benefit obligations and benefit plan cost for 2008 are outlined in the following table. The sensitivities of each key assumption have been calculated independently of changes in other key assumptions. Actual experience may result in changes in a number of assumptions simultaneously.

20. EMPLOYEE FUTURE BENEFITS (continued)

	2008 Pension Benefit Plans		2008 Other Post Employment Benefit Plans	
	Accrued Benefit Obligation	Benefit Plan Cost	Accrued Benefit Obligation	Benefit Plan Cost
Expected long term rate of return on plan assets				
1% increase [1]	-	$(4.3)	-	-
1% decrease [1]	-	$ 4.3	-	-
Liability discount rate				
1% increase [1]	$ (80.9)	$(4.6)	$(3.2)	$(0.2)
1% decrease [1]	$102.0	$ 8.0	$ 4.0	$ 0.2
Future compensation rate				
1% increase [1]	$ 20.1	$ 2.7	-	-
1% decrease [1]	$(18.5)	$(2.5)	-	-
Long term inflation rate				
1% increase [1] [2] [3]	$ 36.8	$ 4.5	$ 3.0	$ 0.2
1% decrease [1] [3]	$(64.4)	$(6.8)	$(2.5)	$(0.2)

(1) *Sensitivities are net of the associated regulatory asset (liability) and unrecognized defined benefit plans cost, which reflect an AUC decision to record costs of employee future benefits in the regulated operations, excluding Alberta Power (2000), when paid rather than accrued.*

(2) *The long term inflation rate for pension plans reflects the fact that pension plan benefit payments are indexed to increases in the Canadian Consumer Price Index to a maximum increase of 3.0% per annum.*

(3) *The long term inflation rate for other post employment benefit plans is the assumed annual health care cost trend rate described in the weighted average assumptions.*

Pension benefit plan assets

	2008		2007	
	Amount	**%** `	Amount	%
Plan asset mix:				
Equity securities [1]	**$ 782.2**	**55.9**	$1,000.4	59.3
Fixed income securities [2]	**526.9**	**37.7**	621.7	36.8
Real estate [3]	**64.0**	**4.6**	37.2	2.2
Cash and other assets [4]	**26.0**	**1.8**	29.3	1.7
	$1,399.1	**100.0**	$1,688.6	100.0

(1) *Equity securities consist of investments in domestic and foreign preferred and common shares. At December 31, 2008, the market values of investments in United States' securities and international equities, denominated in a number of different currencies, are $72.5 million and $212.2 million, respectively (2007 – $114.9 million and $308.1 million, respectively).*

(2) *Fixed income securities consist of investments in federal and provincial government and corporate bonds and debentures.*

(3) *Real estate consists of investments in closed-end real estate funds.*

(4) *Cash and other assets consist of cash, short term notes and money market funds.*

20. EMPLOYEE FUTURE BENEFITS (continued)

At December 31, 2008, plan assets include long term debt of CU Inc. having a market value of $13.9 million (2007 – $12.2 million), Class A non-voting and Class B common shares of Canadian Utilities Limited having a market value of $16.1 million (2007 – $18.5 million) and Class I Non-Voting Shares of ATCO Ltd. having a market value of $13.8 million (2007 – $20.0 million).

Funding

Employees are required to contribute a percentage of their salary to the registered defined benefit pension plans. The Corporation is required to provide the balance of the funding, based on triennial actuarial valuations, necessary to ensure that benefits will be fully provided for at retirement. Based on the most recent actuarial valuation for funding purposes as of December 31, 2006, the Corporation is continuing a contribution holiday that began on April 1, 1996 for all but one of the registered pension plans; commencing in 2007, the Corporation is required to make annual contributions of approximately $0.7 million to cover the unfunded liability of that plan. The next actuarial valuation for funding purposes is required as of December 31, 2009. The Government of Alberta has issued a white paper which, if it becomes law, would require an actuarial valuation to be filed as at December 31, 2008 for those plans that wish to continue their contribution holidays in 2009. Depending on the outcome of the full actuarial valuation, current service contributions may be required to resume in 2009.

21. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

The Corporation's Board of Directors ("Board") is responsible for understanding the principal risks of the business in which the Corporation is engaged, achieving a proper balance between risks incurred and the potential return to share owners, and confirming that there are systems in place that effectively monitor and manage those risks with a view to the long-term viability of the Corporation. The Board has established a Risk Review Committee, which reviews significant risks associated with future performance, growth and lost opportunities identified by management that could materially affect the Corporation's ability to achieve its strategic or operational targets. This committee is responsible for confirming that management has procedures in place to mitigate identified risks.

The Corporation is exposed to changes in interest rates, commodity prices and foreign currency exchange rates. The Power Generation segment is affected by the cost of natural gas and the price of electricity in the Province of Alberta and the United Kingdom and the Global Enterprises segment is affected by the cost of natural gas and the price of natural gas liquids. In conducting its business, the Corporation may use various instruments, including forward contracts, swaps and options, to manage the risks arising from fluctuations in exchange rates, interest rates and commodity prices. All such instruments are used only to manage risk and not for trading purposes.

At December 31, 2008, the following derivative instruments were outstanding: interest rate swaps that hedge interest rate risk on the variable future cash flows associated with a portion of long term debt and non-recourse long term debt, foreign currency forward contracts that hedge foreign currency risk on the future cash flows associated with specific firm commitments or anticipated transactions and certain natural gas purchase contracts.

21. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

The derivative assets and liabilities comprise the following:

	2008	2007
Derivative assets – current:		
Interest rate swap agreements	**$ -**	$ 0.2
Foreign currency forward swaps	**1.7**	0.6
	$ 1.7	$ 0.8
Derivative assets – non-current:		
Natural gas purchase contracts	**$60.1**	$72.5
Interest rate swap agreements	**-**	0.8
Foreign currency forward swaps	**0.3**	-
	$60.4	$73.3
Derivative liabilities – current:		
Interest rate swap agreements	**$ 5.4**	$ 1.5
Foreign currency forward swaps	**-**	1.1
	$ 5.4	$ 2.6
Derivatives liabilities – non-current:		
Interest rate swap agreements	**$12.4**	$ 3.3

21. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

Interest rate risk

The Corporation's interest-bearing assets and liabilities include cash and short-term investments, bank indebtedness, long term debt and non-recourse long term debt. The interest rate risk faced by the Corporation is largely a result of its non-recourse long term debt at variable rates and cash and short term investments. The Corporation has converted certain variable rate long term debt and non-recourse long term debt to fixed rate debt through the following interest rate swap agreements:

Financing	Swap Fixed Interest Rate (1)	Variable Debt Interest Rate	Maturity Date	Notional Principal 2008	2007
ATCO Frontec European operations: (€20.8 million)	5.457%	90 day Euribor	October 2010	**$ 35.5**	$ -
Osborne: ($24.9 million AUD (2007 - $30.3 million AUD))	7.343%	Bank Bill Rate in Australia	December 2013	**21.3**	26.3
APALP:	7.790%	90 day BA	November 2008	**-**	1.3
	7.567%	90 day BA	December 2008	**-**	1.8
	7.750%	6 month LIBOR	December 2011	**61.7**	73.7
Joffre:	7.536%	90 day BA	September 2012	**15.6**	19.8
Scotford:	5.332%	90 day BA	September 2008	**-**	51.4
	3.315%	90 day BA	November 2013	**32.6**	-
	3.715%	3 month LIBOR	November 2013	**8.2**	-
Muskeg River:	5.515%	90 day BA	December 2012	**26.1**	32.6
	5.615%	3 month LIBOR	December 2012	**6.5**	8.2
Brighton Beach:	5.867%	90 day BA	June 2009	**8.0**	8.5
	6.605%	90 day BA	March 2019	**32.2**	34.2
Cory:	6.586%	90 day BA	June 2011	**1.5**	2.1
				$249.2	$259.9

BA – Bankers' Acceptance
LIBOR – London Interbank Offered Rate
Euribor – Euro Interbank Offered Rate

(1) *The above swap fixed interest rates include any long term debt margin fees; the margin fees are subject to escalation (Note 11).*

The Corporation has fixed interest rates, either directly or through interest rate swap agreements, on 97% (2007 — 98%) of total long term debt and non-recourse long term debt. Consequently, the exposure to fluctuations in future cash flows, with respect to debt, as a result of changes in market interest rates is limited. Interest rate swaps are designated as cash flow hedges; changes in the fair value of highly effective cash flow hedges, which include all but the Joffre and APALP interest rate swaps, are recorded in other comprehensive income. Changes in the fair value of the Joffre and APALP interest rate swaps were $0.7 million and $2.1 million, respectively, which were recognized in earnings. In the fourth quarter,

the APALP interest rate swap became ineffective. Up to that point, the swap had been highly effective and therefore changes in the fair value were recorded in other comprehensive income. Going forward, changes in the fair value will be recorded in earnings.

The Corporation's cash and short term investments include fixed rate instruments with maturities of generally 90 days or less that are reinvested as they mature. Therefore, the Corporation has exposure to interest rate movements that occur beyond the term of maturity of the fixed rate investments.

Foreign currency exchange rate risk

The Corporation has exposure to changes in the carrying values of its foreign operations, including assets and liabilities, as a result of changes in exchange rates. Gains or losses on translation of self-sustaining foreign operations are included in the foreign currency translation adjustment account in accumulated other comprehensive income. Gains or losses on translation of integrated foreign operations are recognized in earnings.

Foreign currency exchange rate risk arises from financial instruments denominated in a currency other than the functional currency. The Corporation has entered into foreign currency forward contracts in order to fix the exchange rate on certain service contracts, planned equipment expenditures and operational cash flows denominated in U.S. dollars. At December 31, 2008, the contracts consist of purchases of $0.5 million U.S. in return for Canadian dollars and $10.7 million U.S. in return for Australian dollars (2007 — purchases of £0.7 million, $3.1 million U.S. and 7.0 million Euros, and sales of 33.0 million Euros in return for Canadian dollars).

Natural gas purchase contracts and associated power generation revenue contract liability

The Corporation has long term contracts for the supply of natural gas for certain of its power generation projects. Under the terms of certain of these contracts, the volume of natural gas that the Corporation is entitled to take is in excess of the natural gas required to generate power. As the excess volume of natural gas can be sold, the Corporation is required to designate these entire contracts as derivative instruments. The Corporation recognized a non-current derivative asset and records mark-to-market adjustments through earnings as the fair values of these contracts change with changes in future natural gas prices. These natural gas purchase contracts mature in November 2014.

As all but the excess volume of natural gas is committed to the Corporation's power generation obligations, the Corporation could not recognize the entire fair values of these natural gas purchase contracts in its revenues. Consequently, the Corporation has recognized a provision for a power generation revenue contract and records adjustments to the power generation revenue contract liability concurrently with the mark-to-market adjustments for the natural gas purchase contracts derivative asset. This power generation revenue contract liability is included in deferred credits in the consolidated balance sheet.

The mark-to-market adjustment for the derivative asset and the corresponding adjustment for the associated power generation revenue contract liability decreased earnings by $1.1 million, net of income taxes, for the unaudited three months ended December 31, 2008 (2007 – increase of $2.8 million) and decreased earnings by $2.0 million, net of income taxes, for the year ended December 31, 2008 (2007 – increase of $2.9 million). At December 31, 2008, the natural gas purchase contracts derivative asset is $60.1 million (2007 – $72.5 million), a net change of $12.4 million, and the power generation revenue contract liability is $44.6 million (2007 – $54.2 million), a net change of $9.6 million.

21. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

Credit risk

For cash and short term investments and accounts receivable, credit risk represents the carrying amount on the consolidated balance sheet. Cash and short term investments credit risk is reduced by investing in instruments issued by credit worthy financial institutions and in federal government issued short term instruments. Approximately 85% of the short term investments at December 31, 2008 were invested in Government of Canada treasury bills and certificates of deposit issued by Canadian financial institutions.

Derivative credit risk arises from the possibility that a counterparty to a contract fails to perform according to the terms and conditions of that contract. Derivative credit risk is minimized by dealing with large, credit-worthy counterparties in accordance with established credit approval policies.

The maximum exposure to credit risk is the carrying value of loans and receivables and derivative financial instruments on the balance sheet. The Corporation does not have a concentration of credit risk with any counterparties. A significant portion of loans and receivables arise from the Corporation's operations in Alberta.

Accounts receivable credit risk is reduced by a large and diversified customer base, requirement of letters of credit, and, for regulated operations other than Alberta Power (2000), the ability to recover an estimate for doubtful accounts through approved customer rates.

Accounts receivable are non-interest bearing and are generally due in 30 to 90 days. At December 31, 2008, the provision for impairment of credit losses was $1.9 million. The changes in the provision for impairment were as follows:

	2008
Provision at beginning of year	**$ 1.5**
Impairment of receivables	**0.5**
Receivables written off as uncollectible	**(0.1)**
Provision at end of year	**$ 1.9**

At December 31, 2008, the aging analysis of trade receivables that are past due but not impaired is as follows:

	2008
30 to 90 days	**$10.1**
Greater than 90 days	**2.2**
	$12.3

No other impairments have been identified within accounts receivable.

21. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

Liquidity risk

Liquidity risk is the risk that the Corporation will not be able to meet its obligations associated with financial liabilities. Funds generated by operations provide a substantial portion of the Corporation's cash requirements. Additional cash requirements are met with the use of existing cash balances and externally through bank borrowings and the issuance of long term debt, non-recourse long term debt and preferred shares. Commercial paper borrowings and short term bank loans are used under available credit lines to provide flexibility in the timing and amounts of long term financing. The Corporation has a policy not to invest any of its cash balances in asset backed securities; consequently, the recent turmoil in the asset-backed commercial paper market has had no impact on the Corporation.

The Corporation has contractual obligations in the normal course of business; future minimum undiscounted contractual maturities are as follows:

	2009	2010	2011	2012	2013	2014 and thereafter
Accounts payable and accrued liabilities	$479.5	$ -	$ -	$ -	$ -	$ -
Operating leases [1]	21.6	20.0	17.2	12.6	11.7	49.4
Purchase obligations:						
Coal purchase contracts [2]	50.2	51.2	52.8	89.1	54.9	308.7
Natural gas purchase contracts [3]	46.7	37.4	11.3	5.8	0.4	-
Operating and maintenance agreements [4]	18.2	16.5	19.3	15.3	17.8	48.9
Capital expenditures [5]	133.5	4.3	-	-	-	-
Derivatives [6]	5.1	4.5	3.3	2.4	1.9	5.5
Other	0.9	0.6	0.6	0.4	0.2	0.2
	$755.7	$134.5	$104.5	$125.6	$86.9	$412.7

(1) *Operating leases are comprised primarily of long term leases for office premises and equipment.*
(2) *Alberta Power (2000) has fixed price long term contracts to purchase coal for its coal-fired generating plants.*
(3) *Natural gas purchase contracts consist primarily of ATCO Power contracts to purchase natural gas for certain of its natural gas-fired generating plants.*
(4) *ATCO Power and Alberta Power (2000) have long term service agreements with suppliers to provide operating and maintenance services at certain of their generating plants.*
(5) *Various contracts to purchase goods and services with respect to capital expenditures.*
(6) *Payments on outstanding derivatives have been estimated using rates in effect at December 31, 2008.*

21. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

Fair value of non-derivative financial instruments

The carrying values and fair values of the Corporation's non-derivative financial instruments are as follows:

	2008		2007	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value
Financial Assets				
Held For Trading:				
Cash [(1)]	**$ 31.7**	**$ 31.7**	$ 191.7	$ 191.7
Held to Maturity:				
Short term investments [(1)]	**716.9**	**716.9**	555.5	555.5
Loans and Receivables:				
Accounts receivable [(1)]	**385.5**	**385.5**	373.9	373.9
Financial Liabilities				
Held For Trading:				
Bank indebtedness [(1)]	**22.0**	**22.0**	-	-
Other Liabilities:				
Accounts payable and accrued liabilities[(2)]	**479.5**	**479.5**	388.9	388.9
Liabilities to customers for future income taxes [(3)] (see Note 12)	**19.2**	**19.2**	25.8	25.8
Long term debt [(3)]	**2,862.0**	**2,879.1**	2,603.2	2,907.5
Non-recourse long term debt [(3)]	**457.2**	**489.1**	543.5	578.0

(1) *Recorded at cost. Fair value approximates the carrying amounts due to the short term nature of the financial instruments and negligible credit losses.*

(2) *Recorded at cost. Fair value approximates the carrying amounts due to the short term nature of the financial instruments.*

(3) *Recorded at amortized cost. Fair values are determined using quoted market prices for the same or similar issues. Where the market prices are not available, fair values are estimated using discounted cash flow analysis based on the Corporation's current borrowing rate for similar borrowing arrangements.*

21. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

Fair value of derivative financial instruments

The fair values of the Corporation's derivative financial instruments are as follows:

	2008			2007		
	Notional Principal[1]	**Fair Value Receivable (Payable)[3]**	**Maturity**	Notional Principal[1]	Fair Value Receivable (Payable)[3]	Maturity
Held For Trading:						
Interest rate swaps	**$249.2**	**$(17.8)**	**2009-2019**	$259.9	$(3.8)	2008-2019
Foreign currency forward contracts	**$ 12.3**	**$ 2.0**	**2009-2010**	$ 62.6	$(0.5)	2008
Natural gas purchase contracts	**N/A [2]**	**$ 60.1**	**2014**	N/A [2]	$72.5	2014

(1) *The notional principal is not recorded in the consolidated financial statements as it does not represent amounts that are exchanged by the counterparties.*

(2) *The notional amount for the natural gas purchase contracts is the maximum volumes that can be purchased over the terms of the contracts.*

(3) *Fair values for the interest rate swaps and the foreign currency forward contracts have been estimated using period-end market rates, and fair values for the natural gas purchase contracts have been estimated using period-end forward market prices for natural gas. These fair values approximate the amount that the Corporation would either pay or receive to settle the contract at December 31.*

Sensitivity analysis

The analysis below illustrates the extent to which the Corporation's results are impacted by financial instruments and the underlying market risks (interest rate risk, foreign currency exchange risk, and commodity price risk). Non-derivative financial instruments (listed on the previous page) are recorded at cost and these carrying amounts are not affected by changes in market variables whereas carrying amounts of derivative financial instruments are affected by market variables.

The following table reflects the sensitivity in the fair value of outstanding derivative instruments to reasonably possible changes in Canadian, Australian and Euribor interest rates, the foreign currency exchange rates of the Canadian dollar to the U.S. dollar, the Australian dollar to the U.S. dollar and the forward price of natural gas. The analysis excludes the impact that changes in the underlying market risks would have on non-financial assets and liabilities, foreign currency translation of self-sustaining foreign operations included in accumulated other comprehensive income, and carrying value of employee future benefits. Sensitivities are reflected in changes to earnings and other comprehensive income, after income taxes.

21. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

Assumptions made in arriving at the sensitivity analysis are as follows:

- Changes in the fair value of derivative instruments that are effective cash flow hedges from movements in interest rates or foreign currency exchange rates are recorded in other comprehensive income.
- Changes in the fair value of derivative instruments that are not designated as hedges, that are fair value hedges or that are ineffective cash flow hedges are recorded in earnings.
- Balance sheet sensitivity to interest rates and foreign currency exchange rates relates only to derivative instruments. There are no available for sale financial assets and other liabilities are carried at amortized cost, in which case the carrying values are not affected by changes in interest rates and foreign currency exchange rates.
- Changes in the forward price of natural gas affect the mark to market adjustment of the natural gas purchase contracts derivative asset and the corresponding adjustment for the associated power generation revenue contract liability.

	Year Ended December 31, 2008	
	Earnings	Other Comprehensive Income
Canadian interest rates		
25 basis points increase	$ 0.3	$ 0.8
25 basis points decrease	$ (0.3)	$ (0.8)
Australian interest rates		
25 basis points increase	$ -	$ 0.1
25 basis points decrease	$ -	$ (0.1)
Euribor interest rates		
25 basis points increase	$ -	$ (0.1)
25 basis points decrease	$ -	$ 0.1
U.S. dollar to Canadian dollar exchange rate		
10% increase	$ 2.6	$ -
10% decrease	$ (2.6)	$ -
Forward price of natural gas		
10% increase	$ 2.6	$ -
10% decrease	$ (2.6)	$ -

The sensitivity to a change in the Australian dollar to the U.S. dollar exchange rate of +/- 10% is less than $0.1 million.

22. OTHER COMPREHENSIVE INCOME

Other comprehensive income ("OCI") of the Corporation is comprised of three components: the unrealized gains and losses on effective cash flow hedging instruments, the unrealized gains and losses on financial assets that are available for sale, and the foreign currency translation adjustment relating to self-sustaining foreign operations.

Changes in the components of accumulated OCI are summarized below:

	2008	2007
Accumulated OCI at beginning of period:		
Cash flow hedge losses [1]	**$ (4.6)**	$ -
Foreign currency translation adjustment	**(28.5)**	3.1
	(33.1)	3.1
Adjustment to accumulated OCI at beginning of period due to change in method of accounting for:		
Cash flow hedge losses [2]	**-**	(7.4)
Financial assets available for sale [3]	**-**	0.1
	-	(7.3)
OCI for the period:		
Changes in fair values of cash flow hedges [4]	**(7.7)**	2.7
Transfers of cash flow hedge losses to earnings [3]	**0.8**	0.1
Transfer of gain on financial assets available for sale to earnings [3]	**-**	(0.1)
	(6.9)	2.7
Foreign currency translation adjustment	**(15.1)**	(31.6)
	(22.0)	(28.9)
Accumulated OCI at end of period:		
Cash flow hedge losses [5]	**(11.5)**	(4.6)
Foreign currency translation adjustment	**(43.6)**	(28.5)
	$(55.1)	$(33.1)

(1) *Net of income taxes of $1.9 million.*
(2) *Net of income taxes of $3.2 million*
(3) *Net of income taxes of nil.*
(4) *Net of income taxes of $2.3 million and $(1.3) million, respectively.*
(5) *Net of income taxes of $4.2 million and $1.9 million, respectively.*

23. CONTINGENCIES

Measurement inaccuracies occur from time to time with respect to ATCO Electric's, ATCO Gas' and ATCO Pipelines' metering facilities. Measurement adjustments are settled between the parties based on the requirements of the Electricity and Gas Inspections Act (Canada) and applicable regulations issued pursuant thereto. There is a risk of disallowance of the recovery of a measurement adjustment if controls and timely follow-up are found to be inadequate by the AUC.

The Corporation is party to a number of other disputes and lawsuits in the normal course of business. The Corporation believes that the ultimate liability arising from these matters will have no material impact on the consolidated financial statements.

As a result of decisions of the Supreme Court of Canada in Garland vs. Consumers' Gas Co., the imposition of late payment penalties on utility bills has been called into question. The Corporation is unable to determine at this time the impact, if any, that these decisions will have on the Corporation.

In 2004, ATCO Gas and ATCO Electric transferred their retail energy supply businesses to Direct Energy Marketing Limited and one of its affiliates (collectively "DEML"), a subsidiary of Centrica plc. ATCO Gas and ATCO Electric continue to own and operate the natural gas and electricity distribution systems used to deliver energy.

Although ATCO Gas and ATCO Electric transferred to DEML certain retail functions, including the supply of natural gas and electricity to customers and billing and customer care functions, the legal obligations of ATCO Gas and ATCO Electric remain if DEML fails to perform. In certain events (including where DEML fails to supply natural gas and/or electricity and ATCO Gas and/or ATCO Electric are ordered by the AUC to do so), the functions will revert to ATCO Gas and/or ATCO Electric with no refund of the transfer proceeds to DEML by ATCO Gas and/or ATCO Electric.

Centrica plc, DEML's parent, has provided a $300 million guarantee, supported by a $235 million letter of credit in respect of DEML's obligations to ATCO Gas, ATCO Electric and ATCO I-Tek in respect of the ongoing relationships contemplated under the transaction agreements. However, there can be no assurance that the coverage under these agreements will be adequate to cover all of the costs that could arise in the event of a reversion of such functions.

Canadian Utilities Limited has provided a guarantee of ATCO Gas', ATCO Electric's and ATCO I-Tek's payment and indemnity obligations to DEML contemplated under the transaction agreements.

24. SEGMENTED INFORMATION

Description of segments

The Corporation operates in the following business segments:

The **Utilities** Business Group includes the regulated distribution of natural gas by ATCO Gas, the regulated transmission and distribution of water by CU Water, the regulated transmission of natural gas by ATCO Pipelines, the regulated distribution and transmission of electric energy by ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical, and the provision of non-regulated projects by ATCO Energy Solutions.

24. SEGMENTED INFORMATION (continued)

The **Power Generation** Business Group includes the non-regulated supply of electricity and cogeneration steam by ATCO Power, the regulated supply of electricity by Alberta Power (2000), and the sale of fly ash and other combustion by-products produced in coal-fired electrical generating plants by ASHCOR Technologies.

The **Global Enterprises** Business Group includes the non-regulated gathering, processing, storage, purchase and sale of natural gas by ATCO Midstream, the provision of project management and technical services for customers in the resource, defence and telecommunications sectors by ATCO Frontec, the development, operation and support of information systems and technologies and the provision of billing services, payment processing, credit, collection and call centre services by ATCO I-Tek and the sale of travel services to both business and consumer sectors by ATCO Travel.

The Corporate and Other segment includes commercial real estate owned by the Corporation in Alberta.

Segmented results – Three months ended December 31

2008 2007	Utilities	Power Generation	Global Enterprises	Corporate and Other	Intersegment Eliminations	Consolidated
(Unaudited)						
Revenues – external	**$324.9** $306.8	**$249.1** $193.9	**$169.8** $155.8	**$ 0.5** $ 0.6	**$ -** $ -	**$744.3** $657.1
Revenues – intersegment[(1)]	**6.4** 6.5	**-** -	**39.2** 42.4	**3.1** 2.9	**(48.7)** (51.8)	**-** -
Revenues	**$331.3** $313.3	**$249.1** $193.9	**$209.0** $198.2	**$ 3.6** $ 3.5	**$(48.7)** $(51.8)	**$744.3** $657.1
Earnings attributable to Class A and Class B shares	**$ 45.8** $ 48.0	**$ 46.0** $ 25.5	**$ 31.9** $ 27.7	**$(9.3)** $(4.1)	**$ (0.2)** $ 1.6	**$114.2** $ 98.7

(1) *Intersegment revenues are recognized on the basis of prevailing market or regulated prices.*

24. SEGMENTED INFORMATION (continued)

Segmented results – Year ended December 31

2008 2007	Utilities	Power Generation	Global Enterprises	Corporate and Other	Intersegment Eliminations	Consolidated
Revenues – external	**$1,237.1**	**$ 889.6**	**$650.5**	**$ 1.7**	**$ -**	**$2,778.9**
	$1,091.4	$ 773.0	$538.6	$ 1.9	$ -	$2,404.9
Revenues – intersegment [1]	**25.4**	**-**	**140.2**	**12.7**	**(178.3)**	**-**
	25.1	-	134.0	11.7	(170.8)	-
Revenues	**1,262.5**	**889.6**	**790.7**	**14.4**	**(178.3)**	**2,778.9**
	1,116.5	773.0	672.6	13.6	(170.8)	2,404.9
Operating expenses	**719.8**	**505.0**	**569.3**	**17.7**	**(176.3)**	**1,635.5**
	640.6	422.6	486.1	18.6	(166.3)	1,401.6
Depreciation and amortization	**248.5**	**100.4**	**37.2**	**3.4**	**(0.4)**	**389.1**
	223.7	97.2	29.1	1.5	-	351.5
Interest expense	**157.6**	**70.6**	**6.4**	**192.6**	**(193.7)**	**233.5**
	140.6	79.0	2.9	171.9	(177.0)	217.4
Interest and other income	**(25.4)**	**(10.2)**	**(4.4)**	**(212.8)**	**193.7**	**(59.1)**
	(16.6)	(20.6)	(2.7)	(201.4)	177.0	(64.3)
Earnings before income taxes	**162.0**	**223.8**	**182.2**	**13.5**	**(1.6)**	**579.9**
	128.2	194.8	157.2	23.0	(4.5)	498.7
Income taxes	**3.1**	**71.4**	**55.3**	**5.0**	**(0.5)**	**134.3**
	(22.2)	57.6	47.2	(1.2)	(3.7)	77.7
	158.9	**152.4**	**126.9**	**8.5**	**(1.1)**	**445.6**
	150.4	137.2	110.0	24.2	(0.8)	421.0
Dividends on equity preferred shares	**9.9**	**1.4**	**-**	**21.2**	**-**	**32.5**
	10.7	2.5	-	21.1	-	34.3
Earnings attributable to Class A and Class B shares	**$ 149.0**	**$ 151.0**	**$126.9**	**$ (12.7)**	**$ (1.1)**	**$ 413.1**
	$ 139.7	$ 134.7	$110.0	$ 3.1	$ (0.8)	$ 386.7
Total assets	**$4,766.7**	**$2,125.8**	**$390.6**	**$591.3**	**$ (10.0)**	**$7,864.4**
	$4,122.8	$2,187.4	$345.2	$562.5	$ 87.3	$7,305.2
Purchase of property, plant and equipment	**$ 869.4**	**$ 75.8**	**$ 56.2**	**$ 9.5**	**$ -**	**$1,010.9**
	$ 588.9	$ 49.2	$ 62.7	$ -	$ -	$ 700.8

[1] *Intersegment revenues are recognized on the basis of prevailing market or regulated prices.*

Geographic segments

	Domestic		Foreign		Consolidated	
	2008	2007	**2008**	2007	**2008**	2007
Revenues	**$2,396.2**	$2,143.8	**$382.7**	$261.1	**$2,778.9**	$2,404.9
Property, plant and equipment	**$5,901.1**	$5,369.5	**$307.4**	$309.0	**$6,208.5**	$5,678.5

Management's Discussion and Analysis (MD&A)
For the year ended December 31, 2008

This MD&A should be read in conjunction with the Company's unaudited consolidated financial statements for the three months ended December 31, 2008, and the audited consolidated financial statements for the year ended December 31, 2008. This MD&A is dated February 17, 2009. Additional information relating to the Company, including the Company's annual information form, is available on SEDAR at www.sedar.com.

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Glossary

Adjusted Earnings means earnings attributable to Class A and Class B Shares after adjustment for items that are not in the normal course of business nor a result of day-to-day operations. These items are usually of a non-recurring or one-time nature. Refer to Reconciliation of Earnings Attributable to Class A and Class B Shares and Adjusted Earnings section for a description of these items (non GAAP item).

Adjusted Earnings per Class A and Class B Share is calculated by dividing Adjusted Earnings for a period by the weighted average number of Class A and Class B Shares outstanding during the period (non GAAP item).

AESO means the Alberta Electric System Operator.

Alberta Power Pool means the market for electricity in Alberta operated by AESO.

AUC means the Alberta Utilities Commission and its predecessor, the Alberta Energy and Utilities Board.

Availability is a measure of time, expressed as a percentage of continuous operation, that a generating unit is capable of producing electricity, regardless of whether the unit is actually generating electricity.

Carbon offset means a financial instrument representing a reduction in greenhouse gas emissions. Companies, governments and other entities buy carbon offsets in order to comply with caps on the total amount of greenhouse gases they are allowed to emit or to mitigate their greenhouse gas emissions.

Class A Shares means Class A non-voting shares of the Company.

Class B Shares means Class B common shares of the Company.

Class I Shares means Class I Non-Voting Shares of ATCO Ltd.

Class II Shares means Class II Voting Shares of ATCO Ltd.

Company means Canadian Utilities Limited and, unless the context otherwise requires, includes its subsidiaries.

Frac spread means the premium or discount between the purchase price of natural gas and the selling price of extracted natural gas liquids on a heat content equivalent basis.

GAAP means Canadian generally accepted accounting principles.

GHG means any greenhouse gas which has the potential to retain heat in the atmosphere, including water vapour, carbon dioxide, methane, nitrous oxide and hydrofluorocarbons.

Gigajoule (GJ) means a unit of energy equal to approximately 948.2 thousand British thermal units.

Mark-to-market means assigning a value to a contract or financial instrument based on the current market prices for that contract or instrument or similar contracts or instruments.

Megawatt (MW) is a measure of electric power equal to 1,000,000 watts.

Megawatt hour (MWh) means a measure of electricity consumption equal to the use of 1,000,000 watts of power over a one-hour period.

NGL means natural gas liquids, such as ethane, propane, butane and pentanes plus, that are extracted from natural gas and sold as distinct products or as a mix.

OPEB means other post employment benefits, which principally include health, dental and life insurance payments for retirees and their dependants.

Petajoule (PJ) means a unit of energy equal to approximately 948.2 billion British thermal units.

Placeholder means an AUC approved interim cost which has been included in utility customer rates pending an AUC review in a separate or future proceeding. This cost is subject to adjustment once the separate or future proceeding is completed and may result in refunds to or recoveries from customers.

PPA means Power Purchase Arrangements that became effective on January 1, 2001, as part of the process of restructuring the electric utility business in Alberta. The PPAs are legislatively mandated and approved by the AUC.

Propane plus means propane, butane, pentane and other hydrocarbons other than methane and ethane.

Shrinkage gas means the natural gas which is used to replace, on a heat equivalent basis, the NGL extracted during NGL extraction operations.

Spark spread means the difference between the selling price of electricity and the marginal cost of producing electricity from natural gas. In this MD&A, spark spreads are based on an approximate industry heat rate of 7.5 GJ per MWh.

U.K. means United Kingdom.

Company Overview

Canadian Utilities Limited, an Alberta-based worldwide organization of companies with assets of approximately $7.9 billion, and more than 6,800 employees, is comprised of three main business divisions: Utilities (natural gas and electric transmission and distribution); Power Generation; and Global Enterprises (technology, logistics and energy services).

The consolidated financial statements include the accounts of Canadian Utilities Limited and all of its subsidiaries. The consolidated financial statements have been prepared in accordance with GAAP and the reporting currency is the Canadian dollar.

The Company operates in the following business segments:

The **Utilities** Business Group includes:

- the regulated distribution of natural gas by ATCO Gas;
- the regulated transmission and distribution of water by CU Water;
- the regulated transmission of natural gas by ATCO Pipelines;
- the regulated distribution and transmission of electric energy by ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical; and
- the provision of non-regulated projects by ATCO Energy Solutions.

The **Power Generation** Business Group includes:

- the non-regulated supply of electricity and cogeneration steam by ATCO Power;
- the regulated supply of electricity by Alberta Power (2000); and
- the sale of fly ash and other combustion byproducts produced in coal-fired electrical generating plants by ASHCOR Technologies.

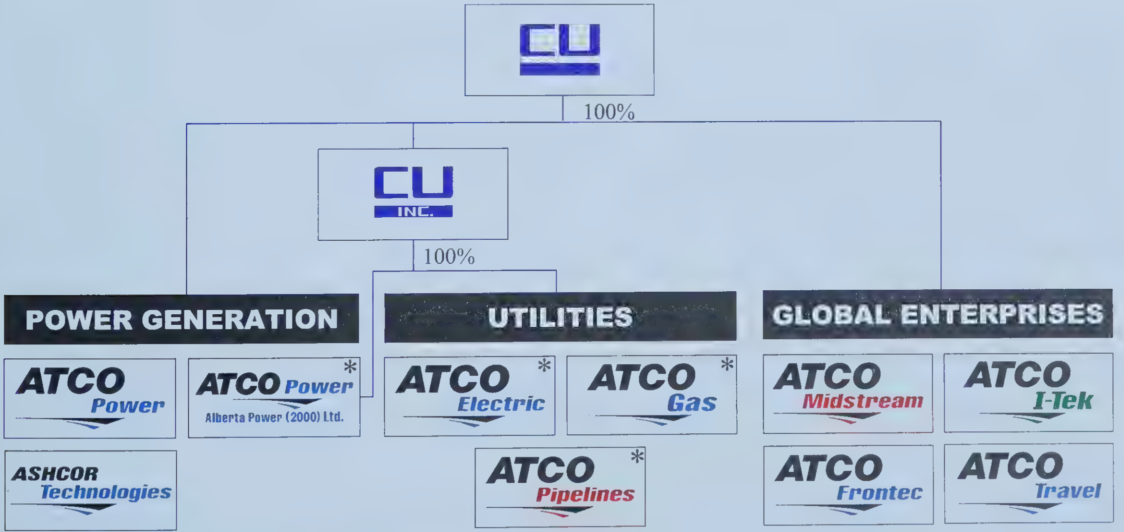
The **Global Enterprises** Business Group includes:

- the non-regulated gathering, processing, storage, purchase and sale of natural gas by ATCO Midstream;
- the provision of project management and technical services for customers in the resource, defence and telecommunications sectors by ATCO Frontec;
- the development, operation and support of information systems and technologies, and the provision of billing services, payment processing, credit, collection and call centre services by ATCO I-Tek; and
- the sale of travel services to both business and consumer sectors by ATCO Travel.

The **Corporate and Other** segment includes cash balances and commercial real estate owned by the Company in Alberta.

Transactions between business segments are eliminated in all reporting of the Company's consolidated financial information. For additional information on the Company's business segments, refer to Note 24 to the consolidated financial statements.

Simplified Organizational Structure



* Regulated operations include ATCO Electric, ATCO Gas, ATCO Pipelines and the generating plants of Alberta Power (2000) Ltd.

POTENTIAL TRANSACTION COMBINING ATCO STRUCTURES AND ATCO FRONTEC

The Company's Board of Directors has established a special committee of independent directors of the Board to review a transaction that would combine the operations of ATCO Structures, a wholly owned subsidiary of ATCO Ltd., and of ATCO Frontec Corp., a wholly-owned subsidiary of the Company. The mandate of the special committee is to investigate, review, assess and evaluate the proposed transaction with the assistance of independent legal and financial advisors. The proposed transaction is subject to Board of Directors', regulatory and other applicable approvals and there can be no assurance that acceptable terms will be concluded or that this transaction will be completed. It is now expected that the committee will make a recommendation to the Board of Directors in the first six months of 2009.

FINANCIAL MARKETS

Significant challenges are currently being experienced in domestic and international financial markets. These challenges are having an impact on the ability of certain borrowers to finance existing operations and capital programs. As discussed elsewhere in this MD&A, the Utilities Business Group has a capital program of $2.0 billion and, depending on infrastructure spending, could be as much as $4.0 billion over the next three years. The Company completed a $325 million debenture issue in May 2008 to fund the 2008 portion of the Utilities Business Group's capital program and to fund scheduled maturities of previous debenture issues. On January 28, 2009, ATCO Power entered into an Australian $100 million credit facility with the Commonwealth Bank of Australia to finance the design and construction of the Karratha generating plant located in Western Australia. In addition, the Company has cash balances of approximately $0.7 billion and available committed and uncommitted lines of credit of approximately $0.9 billion which can be utilized for general corporate purposes.

While the current financial situation has not directly impacted the Company's ability to fund capital projects and ongoing operations, future borrowing may be impacted by these financial markets through increased carrying costs and the ability to raise debt and equity capital. The Company is unable to determine what future changes in the financial markets could occur and how these changes could affect the Company. In addition, the deterioration in the domestic and international economic activity may impact the operations of the Company.

COMMODITY PRICES

Commodity prices, particularly oil and natural gas prices, have fallen significantly since September 2008. These lower prices have had an impact on the Company's operations, particularly the lower frac spreads on ATCO Midstream's NGL business. The Company is unable to determine what future changes in commodity markets could occur and how these changes could affect the Company.

PENSION PLANS

Recent declines in stock and bond markets have resulted in a reduction in the value of the Company's defined benefit pension plans, creating a pension plan deficit that may require the Company to make contributions to the pension plans commencing in 2009.

Employees are required to contribute a percentage of their salary to the registered defined benefit pension plans. The Company is required to provide the balance of the funding, based on triennial actuarial valuations, necessary to ensure that benefits will be fully provided for at retirement. Based on the most recent actuarial valuation for funding purposes as of December 31, 2006 the Company is continuing a contribution holiday that began on April 1, 1996 for all but one of the registered pension plans; commencing in 2007, the Company is required to make annual contributions of approximately

$0.7 million to cover the unfunded liability of that plan. The next actuarial valuation for funding purposes is required as of December 31, 2009. The government of Alberta has issued a white paper which, if it becomes law, would require an actuarial valuation to be filed as at December 31, 2008, for those plans that wish to continue their contribution holidays in 2009. Depending on the outcome of the full actuarial valuation, current service contributions may be required to resume in 2009.

Forward-Looking Information

Certain statements contained in this MD&A constitute forward-looking information. Forward-looking information is often, but not always, identified by the use of words such as "anticipate", "plan", "estimate", "expect", "may", "will", "intend", "should", and similar expressions. Forward-looking information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information. The Company believes that the expectations reflected in the forward-looking information are reasonable, but no assurance can be given that these expectations will prove to be correct and such forward-looking information should not be unduly relied upon.

Non-GAAP Measures

The Company uses the measures "funds generated by operations", "Adjusted Earnings" and "Adjusted Earnings per Class A and Class B Share" in this MD&A. These measures do not have any standardized meaning under GAAP and might not be comparable to similar measures presented by other companies.

Funds generated by operations is defined as cash flow from operations before changes in non-cash working capital. In management's opinion, funds generated by operations is a significant performance indicator of the Company's ability to generate cash during a period to fund its capital expenditures without regard to changes in non-cash working capital during the period.

Adjusted Earnings is defined as earnings attributable to Class A and Class B Shares after adjustment for items that are not in the normal course of business nor a result of day-to-day operations. These items are usually of a non-recurring or one-time nature. Management believes Adjusted Earnings allow for a more effective analysis of operating performance and trends. A reconciliation of Adjusted Earnings to earnings attributable to Class A and Class B Shares is presented in the Results of Operations – Reconciliation of Earnings Attributable to Class A and Class B Shares and Adjusted Earnings section.

Controls and Procedures

DISCLOSURE CONTROLS AND PROCEDURES

As of December 31, 2008, the Company's management evaluated the effectiveness of the Company's disclosure controls and procedures, as defined under rules adopted by the Canadian Securities Administrators. This evaluation was performed under the supervision of, and with the participation of, the Chief Executive Officer (CEO) and the Chief Financial Officer (CFO).

Disclosure controls and procedures are controls and other procedures designed to provide reasonable assurance that information required to be disclosed in documents filed with securities regulatory authorities is recorded, processed, summarized and reported on a timely basis and is accumulated and communicated to the Company's management, including the CEO and the CFO, as appropriate, to allow timely decisions regarding required disclosure.

The Company's management, inclusive of the CEO and the CFO, does not expect that the Company's disclosure controls and procedures will prevent or detect all error and all fraud. The inherent limitations in all control systems are such that they can provide only reasonable, not absolute, assurance that all control issues and instances of fraud or error, if any, within the Company have been detected.

Based on this evaluation, the CEO and the CFO have concluded that, subject to the inherent limitations noted above, the Company's disclosure controls and procedures are effective in providing reasonable assurance that material information relating to the Company and its consolidated subsidiaries is made known to the CEO and the CFO by others within those entities on a timely basis.

INTERNAL CONTROL OVER FINANCIAL REPORTING

As of December 31, 2008, the Company's management evaluated the effectiveness of the Company's internal control over financial reporting, as defined under rules adopted by the Canadian Securities Administrators. This evaluation was performed under the supervision of, and with the participation of, the CEO and the CFO.

The Company's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Internal control over financial reporting, no matter how well designed, has inherent limitations. Therefore, internal control over financial reporting can provide only reasonable assurance with respect to financial statement preparation and may not prevent or detect all misstatements.

Based on this evaluation, the CEO and the CFO have concluded that, subject to the inherent limitations noted above, the Company's internal control over financial reporting is effective in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

There was no change in the Company's internal control over financial reporting that occurred during the period beginning on October 1, 2008, and ended on December 31, 2008, that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

Annual Results of Operations

SELECTED INFORMATION

($ millions, except per share data, outstanding shares and % return on equity) [1] [2]	For the Year Ended December 31 **2008**	2007	2006
Revenues	**2,778.9**	2,404.9	2,430.4
Earnings attributable to Class A and Class B shares	**413.1**	386.7	323.9
Adjusted Earnings [3]	**401.8**	343.8	320.8
Total assets	**7,864.4**	7,305.2	6,993.5
Long term debt	**2,844.3**	2,603.2	2,411.5
Non-recourse long term debt	**412.4**	478.1	626.7
Equity preferred shares	**625.0**	625.0	636.5
Class A and Class B share owners' equity	**2,751.7**	2,521.7	2,324.7
Return on equity	**15.7**	16.0	14.3
Cash flow from operations	**791.8**	706.9	617.9
Funds generated by operations	**804.6**	725.9	657.5
Capital expenditures	**1,010.9**	700.8	567.7
Earnings per Class A and Class B share	**3.29**	3.08	2.57
Diluted earnings per Class A and Class B share	**3.28**	3.07	2.56
Adjusted Earnings per Class A and Class B share [3]	**3.20**	2.74	2.54
Cash dividends declared per share:			
Series Second Preferred Shares:			
Series O [4]	**1.09**	1.13	1.26
Series Q [5]	-	0.68	1.48
Series R [5]	-	0.61	1.33
Series S [5]	-	0.77	1.65
Series T [4]	**1.09**	1.09	1.26
Series U [4]	**1.09**	1.09	1.26
Series V [6]	**1.18**	1.28	1.31
Series W	**1.45**	1.45	1.45
Series X	**1.50**	1.50	1.50
Class A and Class B share	**1.33**	1.25	1.40
Equity per Class A and Class B share	**21.92**	20.13	18.54
Class A and Class B shares outstanding, year end (thousands)	**125,510**	125,295	125,388
Weighted average Class A and Class B shares outstanding (thousands):			
Basic	**125,408**	125,409	126,219
Diluted	**125,784**	125,934	126,687

Notes:

(1) *There were no discontinued operations or extraordinary items during these periods.*

(2) *The above data (other than Adjusted Earnings, Adjusted Earnings per Class A and Class B share, return on equity and equity per Class A and Class B share) has been extracted from the financial statements, which have been prepared in accordance with GAAP and the reporting currency is the Canadian dollar.*

(3) *Refer to Significant Non-Operating Financial Items section for a description of adjustments to obtain Adjusted Earnings.*

(4) *The dividend rate was reset to $1.09 (from 5.05% to 4.35%) for the period between December 2, 2006, and December 2, 2011.*

(5) *Series Second Preferred Shares Q, R and S were redeemed on May 18, 2007.*
(6) *The dividend rate was reset to $1.18 (from 5.25% to 4.70%) for the period between October 3, 2007, and October 3, 2012.*

RECONCILIATION OF EARNINGS ATTRIBUTABLE TO CLASS A AND CLASS B SHARES AND ADJUSTED EARNINGS

Adjusted Earnings are referred to in various sections of this MD&A. The following table reconciles Adjusted Earnings, which are earnings attributable to Class A and Class B Shares after adjustments for items that are not in the normal course of business nor a result of day-to-day operations. These items are usually of a non-recurring or one-time nature. A description of each adjustment is provided in the Significant Non-Operating Financial Items section.

	For the Year Ended December 31	
($ millions)	**2008**	2007
Earnings attributable to Class A and Class B Shares	**413.1**	386.7
Mark-to-Market Adjustment (1)	**2.0**	(2.9)
Other Post Employment Benefits (2)	**(7.0)**	-
Federal Court of Appeal Decision – Mining Assets (3)	**(3.0)**	-
2008 Tax Assessment (4)	**(3.3)**	-
2007 Change in the Taxation of Preferred Share Dividends (5)	**-**	(15.6)
2007 Changes in Income Taxes and Rates (6)	**-**	(14.9)
ATCO Gas Tax Reassessments (7)	**-**	(9.5)
Adjusted Earnings	**401.8**	343.8

SIGNIFICANT NON-OPERATING FINANCIAL ITEMS

Consolidated and segmented financial results include the following significant non-operating financial items.

(1) Natural Gas Purchase Contracts and Associated Power Generation Revenue Contract Liability (Mark-to-Market Adjustment)

ATCO Power has long term contracts for the supply of natural gas for certain of its power generation projects. Under the terms of certain of these contracts, the volume of natural gas that the Company is entitled to take is in excess of the natural gas required to generate power. As the excess volume of natural gas can be sold, the Company is required to designate these entire contracts as derivative instruments. The Company recognized a non-current derivative asset and records mark-to-market adjustments through earnings as the fair values of these contracts change with changes in future natural gas prices. These natural gas purchase contracts mature in November 2014.

As all but the excess volume of natural gas is committed to the Company's power generation obligations, the Company could not recognize the entire fair values of these natural gas purchase contracts in its revenues. Consequently, the Company has recognized a provision for a power generation revenue contract and records adjustments to the power generation revenue contract liability concurrently with the mark-to-market adjustments for the natural gas purchase contracts derivative asset. This power generation revenue contract liability is included in deferred credits in the consolidated balance sheet.

The mark-to-market adjustment for the derivative asset and the corresponding adjustment for the associated power generation revenue contract liability decreased earnings by $1.1 million, net of income

taxes, for the unaudited three months ended December 31, 2008 (2007 – increase of $2.8 million) and decreased earnings by $2.0 million, net of income taxes, for the year ended December 31, 2008 (2007 – increase of $2.9 million). At December 31, 2008, the natural gas purchase contracts derivative asset is $60.1 million (2007 – $72.5 million), a net change of $12.4 million, and the power generation revenue contract liability is $44.6 million (2007 – $54.2 million), a net change of $9.6 million.

(2) Other Post Employment Benefits

In June 2008, the Company prospectively changed the method of apportioning the costs of OPEB plans to individual subsidiaries. Formerly, each subsidiary was apportioned a percentage of its payroll costs at a rate calculated for the plan as a whole. The revised method determines the accrued OPEB liabilities and costs on a company-by-company basis. Total consolidated accrued OPEB liabilities and costs did not change. Under the new method of apportioning, the OPEB liability for the regulated subsidiaries, excluding Alberta Power (2000), increased by $10.4 million with a corresponding increase to non-current regulatory assets. Pursuant to an AUC decision effective January 1, 2000, the regulated operations, excluding Alberta Power (2000), are required to expense contributions for other post employment benefit and certain other defined benefit pension plans as paid. Consequently, there was no change to their earnings for the unaudited three months and year ended December 31, 2008. The difference between the amounts accrued and paid is deferred in non-current regulatory assets.

The OPEB liability for Alberta Power (2000) and the non-regulated subsidiaries decreased which resulted in an increase to earnings of $7.0 million, of which $5.5 million was recorded in the second quarter of 2008 and $1.5 million was recorded in the fourth quarter of 2008.

The earnings impact of the OPEB adjustments by Business Group was as follows:

($ millions)	Years Prior to 2008
Power Generation	2.7
Global Enterprises	4.2
Corporate & Other and Intersegment Eliminations	0.1
Total	7.0

(3) Federal Court of Appeal Decision – Mining Assets

On May 22, 2008, the Federal Court of Appeal issued a decision overturning previous Canada Revenue Agency (CRA) reassessments pertaining to the computation of resource allowances and corresponding capital cost allowances for mining assets related to the Company's coal-fired power generation business. On July 8, 2008, the CRA advised that it would not seek leave to appeal to the Supreme Court of Canada in respect of this matter. This appeal and subsequent court decision applies to the 1997 to 1998 taxation years and allows ATCO Electric and Alberta Power (2000), as successor to ATCO Electric in the coal-fired generating plants, to claim additional resource allowance and capital cost allowance. This reduced current income tax expense and increased interest income which resulted in an increase to earnings of $3.0 million.

The earnings impact of this Federal Court of Appeal Tax Decision by Business Group was as follows:

($ millions)	Total
Utilities	2.2
Power Generation	0.8
Total	3.0

(4) 2008 Tax Assessment

In 2008 the Company received a favorable tax decision from the CRA to treat certain previously reported capital outlays as current expenditures for tax purposes in ATCO Electric and ATCO Pipelines. As a result the Company recognized a reduction in current income tax expense and an increase in interest income in respect of prior taxation years which resulted in an increase in earnings of $3.3 million.

(5) 2007 Change in the Taxation of Preferred Share Dividends

In 2007, the federal government announced an amendment to tax legislation pertaining to Part VI.1 tax (the tax payable on preferred share dividends paid by corporations). Prior to this change, corporations that had Part VI.1 tax payable were entitled to an income tax deduction equal to 9/4ths of the Part VI.1 tax payable. Effective January 1, 2003, this deduction was increased to three times the amount of the Part VI.1 tax payable. The CRA has been assessing corporate tax returns based on this proposed change being in effect since January 1, 2003, resulting in a reduction of taxes paid to the Canadian government. In the second quarter of 2007, the Company recorded a one-time reduction to current income tax expense which resulted in increased earnings of $15.6 million relating to years prior to 2007. Funds generated by operations increased by $15.6 million, offset by a similar reduction in changes in non-cash working capital, leaving the Company's cash position unchanged.

The earnings impact of the Part VI.1 tax adjustment by Business Group was as follows:

($ millions)	Years Prior to 2007
Utilities	4.2
Power Generation	1.3
Global Enterprises	1.4
Corporate & Other and Intersegment Eliminations	8.7
Total	15.6

(6) 2007 Changes in Income Taxes and Rates

In 2007, the federal government announced a reduction in corporate tax rates from 19% to 15% by 2012. As a result of these changes, the Company made an adjustment to future income taxes amounting to $10.9 million in the fourth quarter of 2007. This one-time adjustment resulted in increased earnings of $10.9 million relating to the change in the future income tax liability as at December 31, 2006. An additional increase to earnings of $1.5 million was recorded relating to the change in the future income tax liability for the first nine months of 2007.

Additionally, in 2007 the British Parliament enacted a 2% reduction in the corporate income tax rate effective April 1, 2008, which impacted ATCO Power's operations in the U.K. This resulted in a further increase in the Company's 2007 earnings of $4.0 million.

The earnings impact of the 2007 changes in income taxes and rates adjustment by Business Group was as follows:

($ millions)	December 31, 2006 Balance	First Nine Months of 2007	Total
Canadian tax changes:			
Utilities	0.3	-	0.3
Power Generation	8.2	1.3	9.5
Corporate & Other and Intersegment Eliminations	2.4	0.2	2.6
	10.9	1.5	12.4
U.K. tax changes in Power Generation	4.0	-	4.0
Total	14.9	1.5	16.4

(7) ATCO Gas Tax Reassessments

In the fourth quarter of 2007, ATCO Gas successfully appealed previous CRA reassessments which resulted in an $8.8 million decrease in income taxes and an increase in interest income, net of income taxes, of $0.7 million for an overall increase to earnings of $9.5 million. These ATCO Gas CRA reassessments applied to the 1999 to 2006 taxation years and allowed ATCO Gas to treat previously reported capital outlays as current expenditures for income tax purposes.

CONSOLIDATED REVENUES AND EARNINGS

Consolidated 2008 **revenues increased** by $374.0 million (16%) over 2007. This increase was primarily attributable to a $146.0 million (13%) increase in revenues in the Utilities segment, a $116.6 million (15%) increase in revenues in the Power Generation segment and a $118.1 million (18%) increase in revenues in the Global Enterprises segment.

The **increase** in **revenues** was primarily attributable to increased business activity in ATCO Frontec's operations and higher natural gas fuel purchases recovered on a "no-margin" basis, improved merchant operations, increased availability and the recognition of insurance proceeds from the Barking outage in ATCO Power's U.K. operations. In addition, the 2007 refund of future income tax balances with a corresponding decrease in 2007 revenues and the impact of higher 2008 AUC approved customer rates resulting from the 2007 and 2008 ATCO Electric general tariff decision (ATCO Electric GTA) contributed to the increase in revenues. Other contributing factors were AUC approved interim customer rates in ATCO Gas associated with the 2008 and 2009 general rate application (ATCO Gas GRA) and improved merchant performance in ATCO Power's Alberta generating plants. These increases were partially offset by the impact of lower exchange rates on conversion of revenues to Canadian dollars in ATCO Power's U.K. operations, and lower storage revenues due to the timing and demand of natural gas storage capacity sold and lower storage fees in ATCO Midstream.

Earnings in 2008 were $413.1 million, an **increase** of $26.4 million (7%), over 2007, including the impact of the adjustments identified in the Significant Non-Operating Financial Items section.

In 2008, **Adjusted Earnings** were $401.8 million, an **increase** of $58.0 million (17%), over 2007. The primary reasons for the increased Adjusted Earnings were improved merchant performance in ATCO Power's Alberta generating plants and increased availability and the recognition of insurance proceeds from the Barking outage in ATCO Power's U.K. operations. The impact of the ATCO Gas GRA net of cost increases and suspension of the Carbon rate riders (refer to Regulatory Matters – ATCO Gas – Carbon Natural Gas Storage Facility) also contributed to the increase in Adjusted Earnings. Other contributing factors were the impact of the ATCO Electric GTA and increased business activity in ATCO Frontec's operations. These increases were partially offset by lower storage fees in ATCO Midstream.

Interest and other income decreased by $5.2 million to $59.1 million mainly due to the mark-to-market adjustment in ATCO Power and lower rates of interest earned on lower cash balances, partially offset by the recognition of carbon offsets by ATCO Power.

CONSOLIDATED EXPENSES

($ millions)	For the Year Ended December 31		
	2008	2007	Change to 2008 (2008-2007)
Operating expenses:			
Natural gas supply	**37.9**	42.1	(10%)
Purchased power	**54.1**	49.9	8%
Operation and maintenance	**1,123.5**	941.6	19%
Selling and administrative	**244.8**	216.8	13%
Franchise fees	**175.2**	151.2	16%
	1,635.5	1,401.6	17%
Depreciation and amortization	**389.1**	351.5	11%
Interest	**233.5**	217.4	7%
Income taxes	**134.3**	77.7	73%
Dividends on equity preferred shares	**32.5**	34.3	(5%)

In 2008, **operating expenses increased** by $233.9 million (17%) over 2007. Natural gas supply expense decreased primarily as a result of reduced business activity in NGL extraction operations in ATCO Midstream. Operation and maintenance expenses were higher primarily as a result of higher operating and fuel costs on a "no-margin" basis in ATCO Power, increased business activity in ATCO Frontec, and growth in ATCO Electric. Selling and administrative expenses increased primarily as a result of the impact of inflation, increased employment costs associated with higher employment levels resulting from increased growth, and higher project development costs in ATCO Power. Increased franchise fees due to higher natural gas prices, recovered on a flow through basis, were paid in ATCO Gas.

Depreciation and amortization expenses increased by $37.6 million, primarily due to capital additions in 2007 and 2008 in the Utilities segment and in ATCO Frontec.

Interest expense increased by $16.1 million (7%) over 2007 primarily due to increased amounts of debt outstanding (net of redemptions) resulting from new financings issued in 2007 and 2008 to fund capital expenditures in the Utilities segment, partially offset by the repayment of ATCO Power's non-recourse financings in 2007 and 2008.

In 2008, **income taxes increased** by $56.6 million (73%) over 2007, primarily due to the impact of a number of tax adjustments in 2007 and 2008. The following table indicates the significant items included in determining income tax expense for 2007 and 2008.

($ millions)	For the Year Ended December 31, 2008
Income taxes - 2007	77.7
Increase in 2008 income taxes due to higher earnings before tax	24.0
2007 Adjustments:	
2007 Changes in Income Taxes and Rates [(1)]	14.9
2007 Change in the Taxation of Preferred Share Dividends [(1)]	15.6
Refund of ATCO Electric future income taxes [(2)]	34.4
ATCO Gas Tax Reassessments [(1)]	8.8
Flow through adjustments pertaining to rate regulated operations	4.9
2008 Adjustments:	
Change in 2008 tax rates	(13.1)
Tax reassessments	(9.7)
Flow through adjustments pertaining to rate regulated operations	(27.2)
Other	4.0
Income taxes - 2008	134.3

Note:

(1) *Refer to Significant Non-Operating Financial Items section for a description of the adjustments.*

(2) *Refer to Segmented Information – Utilities – Regulatory Developments – ATCO Electric – 2007 and 2008 General tariff Application section.*

Dividends on equity preferred shares decreased by $1.8 million (5%) primarily due to lower dividend rates and lower number of equity preferred shares outstanding.

SEGMENTED INFORMATION

($ millions)	Utilities	Power Generation	Global Enterprises	Corporate & Other	Intersegment Eliminations	Total
			For the Year Ended December 31			
2008						
Revenues	**1,262.5**	**889.6**	**790.7**	**14.4**	**(178.3)**	**2,778.9**
Earnings attributable to Class A and Class B Shares	**149.0**	**151.0**	**126.9**	**(12.7)**	**(1.1)**	**413.1**
Mark-to-Market Adjustment (1)	-	**2.0**	-	-	-	**2.0**
Other Post Employment Benefits (2)	-	**(2.7)**	**(4.2)**	**(0.1)**	-	**(7.0)**
Federal Court of Appeal Decision – Mining Assets (3)	**(2.2)**	**(0.8)**	-	-	-	**(3.0)**
2008 Tax Assessment (4)	**(3.3)**	-	-	-	-	**(3.3)**
Adjusted Earnings	**143.5**	**149.5**	**122.7**	**(12.8)**	**(1.1)**	**401.8**
Capital expenditures	**869.4**	**75.8**	**56.2**	**9.5**	-	**1,010.9**
Operating expenses	**719.8**	**505.0**	**569.3**	**17.7**	**(176.3)**	**1,635.5**
2007						
Revenues	1,116.5	773.0	672.6	13.6	(170.8)	2,404.9
Earnings attributable to Class A and Class B Shares	139.7	134.7	110.0	3.1	(0.8)	386.7
Mark-to-Market Adjustment (1)	-	(2.9)	-	-	-	(2.9)
2007 Changes in the Taxation of Preferred Share Dividends (5)	(4.2)	(1.3)	(1.4)	(8.7)	-	(15.6)
2007 Changes in Income Taxes and Rates (6)	(0.3)	(12.2)	-	-	(2.4)	(14.9)
ATCO Gas Tax Reassessments (7)	(9.5)	-	-	-	-	(9.5)
Adjusted Earnings	125.7	118.3	108.6	(5.6)	(3.2)	343.8
Capital expenditures	588.9	49.2	62.7	-	-	700.8
Operating expenses	640.6	422.6	486.1	18.6	(166.3)	1,401.6

Notes:
(1) to (7) *Refer to Significant Non-Operating Financial Items section for a description of the adjustments.*

Utilities

ATCO Electric, ATCO Gas and ATCO Pipelines are regulated primarily by the AUC, which administers acts and regulations covering such matters as rates, financing, accounting, construction, operation and service area. These utilities are subject to a cost of service regulatory mechanism under which the AUC establishes the revenues required (i) to recover the forecast operating costs, including depreciation and amortization and income taxes, of providing the regulated service, and (ii) to provide a fair and reasonable return on utility investment, or rate base. Rate base for each utility is the aggregate of the AUC approved investment in property, plant and equipment, less accumulated depreciation, and contributions by utility customers for extensions to plant, plus an allowance for working capital. The utilities earn a return on rate base intended to meet the cost of the debt and preferred share components of rate base and to provide share owners with a fair return on the common equity component of rate base.

Utilities **revenues** in 2008 **increased** by $146.0 million (13%) from 2007. Items that contributed to increased revenues were the ATCO Electric GTA, the ATCO Gas GRA and the impact of higher franchise fees collected on behalf of cities and municipalities in ATCO Gas.

Temperatures in ATCO Gas in 2008 were 1.8% colder than normal, compared to 1.0% warmer than normal in 2007. ATCO Gas, pursuant to the AUC decision on its 2008-2009 general rate application issued on November 13, 2008, has received approval to establish deferral accounts deferring the impact of temperature fluctuations on ATCO Gas' revenues commencing January 1, 2008. The deferral account mechanism largely eliminates the impact of temperature on ATCO Gas' earnings.

Earnings for 2008 were $149.0 million, an **increase** of $9.3 million (7%) over 2007, including the impact of the adjustments identified in the Significant Non-Operating Financial Items section.

In 2008, **Adjusted Earnings** were $143.5 million, an **increase** of $17.8 million (14%) over 2007. The primary reasons for higher Adjusted Earnings were the impact of the ATCO Gas GRA net of cost increases and suspension of the Carbon natural gas storage facility rate riders (refer to Regulatory Matters – ATCO Gas – Carbon Natural Gas Storage Facility section) and the impact of the ATCO Electric GTA.

Capital expenditures to maintain capacity and meet planned growth were $869.4 million in 2008. Capital expenditures rose by $280.5 million from 2007 as a result of the rapid growth of the Alberta economy, customer growth, and safety and reliability enhancements. Capital expenditures for 2009 to 2011 are expected to be $2.0 billion and, depending on infrastructure spending, could be as much as $4.0 billion.

Regulatory Developments

The return on common equity for regulated utility operations was established by the AUC using its standardized rate of return methodology for utilities in Alberta. The rate of return was established in 2004 and is adjusted annually by 75% of the change in long term Government of Canada bond yield, similar to the adjustment mechanism used by the National Energy Board. The rate of return in 2008 was 8.75% and for 2009 has been set at a placeholder rate of 8.75%. The rate of return in 2007 was 8.51%. If no rate applications are filed for a particular year, then there will be no adjustment to the common equity rate of return for that year.

Generic Cost of Capital

In February 2008, the AUC initiated a generic proceeding to determine whether the standardized rate of return methodology and the utility capital structures should be reviewed. A regulatory process has been established by the AUC with a hearing rescheduled for May 19, 2009, to review the generic return on equity formula as well as to review the capital structure for each of the Alberta utilities. The AUC also indicated that any changes which result from this proceeding would be applied beginning in 2009. As ATCO Gas filed a general rate application for 2008 and 2009, a separate module within the generic proceeding will address 2008 cost of capital issues relating to the capital structure for ATCO Gas, as inclusion of these issues was removed from its 2008/2009 general rate application. The changes for 2008 and 2009 will not apply to ATCO Pipelines if its negotiated settlement for 2008 and 2009 revenue requirements is approved by the AUC. Approval of the negotiated settlement is expected in the first quarter of 2009.

Benchmarking

ATCO Electric, ATCO Gas, and ATCO Pipelines (the ATCO Utilities) purchase information technology services from ATCO I-Tek. ATCO Electric and ATCO Gas also purchase customer care and billing

services from ATCO I-Tek. The recovery of these costs in customer rates is subject to AUC approval. Since 2003, the costs have been approved on a placeholder basis, and are subject to final AUC approval after completion of a collaborative benchmarking process.

The benchmarking report, dealing with the period of 2003-2007, was received on January 23, 2008. In February 2008, the benchmarking report along with an application to adjust the placeholder rates was filed with the AUC. In April 2008, an agreement with the customer group concerning the adjustment to placeholders was submitted to the AUC for approval. Should this agreement be approved by the AUC, it is not expected to have a material impact on consolidated earnings. The AUC has established a further process for the 2003 – 2007 period with a hearing scheduled for the second quarter of 2009 to review the issues related to the application and subsequent agreement with the customer group.

For the 2008 and 2009 period, a separate regulatory process will occur to approve rates for information technology and customer care and billing services provided by ATCO I-Tek that can be included in customer rates. The 2008-2009 proceeding will commence after the completion of the 2003-2007 process. In 2009, the ATCO Utilities will continue to utilize placeholder rates for information technology and customer care and billing services until final rates are determined by the AUC.

A further regulatory process to deal with rates for information technology and customer care and billing services provided by ATCO I-Tek for 2010 and beyond has been established and the AUC is expected to set a schedule for this regulatory process in the second quarter of 2009.

Utility Asset Disposition Rate Review Proceeding

In March 2008, the AUC initiated a proceeding to consider the potential rate related implications for Alberta utilities of the Supreme Court of Canada's 2006 Calgary Stores Block decision (Stores Block Decision). The Calgary Stores Block matter involved the disposition by ATCO Gas of its Calgary Stores Block facility and adjacent property in downtown Calgary. The Supreme Court held that utility shareholders were entitled to receive all proceeds resulting from the sale.

The AUC has indicated that the Stores Block Decision may have various implications with respect to regulation of Alberta utility companies (including the potential impact of the Carbon Natural Gas Storage Facility decision discussed below). The AUC has stated that it would like to develop a comprehensive understanding of these potential implications through this proceeding and then apply this understanding in a consistent manner in future decisions. At the conclusion of this proceeding, the AUC will issue a decision reflecting its conclusions with respect to the interpretation and application of the guidance provided by the courts and the resulting implications to be used in future proceedings. On November 28, 2008, the AUC suspended the utility asset disposition rate review proceeding until further notice to allow for various related matters currently before the courts to be addressed.

ATCO Electric

2007 and 2008 General Tariff Application

In September 2007, the AUC issued a decision on ATCO Electric's general tariff application for 2007 and 2008. The decision established, among other things, the amount of revenue to be collected in 2007 and 2008 from customers for transmission and distribution services. The AUC also approved a rate of return on common equity of 8.51% for 2007, as determined by its standardized rate of return methodology. The effect of this decision on the earnings of ATCO Electric was not material as higher revenues primarily resulting from increased capital expenditures and previously approved interim customer rates were offset by a lower approved rate of return on common equity (8.51% in 2007 versus 8.93% in 2006) and other adjustments.

The decision also directed ATCO Electric to change its income tax methodology for federal purposes. This change in tax methodology does not affect earnings as ATCO Electric's revenues and income tax expense were reduced by similar amounts. Accordingly, in 2007, ATCO Electric recorded a reduction in future income tax liabilities of $34.4 million and a liability to customers of $48.6 million, offset by a regulatory asset of $14.2 million which represents current income tax savings to be realized in future periods. Unrecorded future income tax liabilities increased by $34.4 million as a result of this decision. In December 2007, ATCO Electric refunded $16.1 million of the liability to transmission customers reducing the liability to customers to $32.5 million. In addition, the $16.1 million refund resulted in current income tax savings of $5.2 million, reducing the regulatory asset to $9.0 million. The total reduction in revenues and income taxes in 2007 was $39.6 million. ATCO Electric began refunding the remaining $32.5 million to distribution customers over a five year period commencing in 2008. ATCO Electric will realize the regulatory asset of $9.0 million over the same 5 year period with no effect on earnings as current income tax savings will be offset by this reduction in revenues.

Transmission Infrastructure Projects

In August 2006, the AUC approved the AESO application for increased transmission infrastructure in northwest Alberta. The AESO has approval to assign to the transmission facility owner, ATCO Electric, work consisting of several distinct projects that is expected to result in 725 kilometres of new transmission lines to be constructed by 2011.

To date, three of these projects have been assigned by the AESO with final approval having been received from the AUC for two projects relating to the construction of 516 kilometres of transmission line with an estimated cost of $390 million and an anticipated completion by March 31, 2010.

As a result of changing economic conditions and completion dates of the remaining distinct projects (post 2010), ATCO Electric is unable to estimate the cost of the entire project at this time.

In addition to the increased transmission infrastructure in northwestern Alberta, ATCO Electric anticipates that an additional 200 - 500 kilometres of transmission line projects will be required in its service area over the next five years.

2009 and 2010 General Tariff Application

In July 2008, ATCO Electric filed a general tariff application with the AUC for 2009 and 2010 requesting, among other things, increased revenues to recover increased financing, depreciation and operating costs associated with increased rate base in Alberta. ATCO Electric filed an application requesting interim refundable rates pending the AUC's decision on the application. In December 2008, ATCO Electric received a decision from the AUC approving interim refundable rate increases amounting to 50% of the requested increase for transmission operations and 25% of the requested increase for distribution operations. A hearing is scheduled for February 2009, with a decision expected by the third quarter in 2009.

ATCO Gas

2005, 2006, and 2007 General Rate Application

In May 2006, the City of Calgary filed a review and variance application with the AUC, alleging that the AUC made errors in ATCO Gas' 2005-2007 general rate application decision related to the calculation of working capital needed by ATCO Gas to operate its Carbon natural gas storage facility. The AUC issued a decision on January 17, 2007, denying the City of Calgary's application. On February 15, 2007, the City

of Calgary filed for leave to appeal this decision with the Alberta Court of Appeal. On June 19, 2007, the appeal was heard with the court granting the City of Calgary leave to appeal on August 31, 2007. The court decided to postpone addressing the appeal, allowing the AUC time to address the Alberta Court of Appeal decision related to the removal of the Carbon assets from regulation.

In October 2006, ATCO Gas filed a review and variance application with the AUC for the ATCO Gas 2005, 2006 and 2007 general rate application decision. The application alleges that the AUC made errors in the decision related to the approved level of administrative expense. In December 2006, the AUC issued a decision which acknowledged an error for a portion of the administrative expense in question. On April 18, 2007, the AUC agreed to review its original decision. On November 27, 2007, a decision on this matter was received granting ATCO Gas $4.7 million in costs to be collected during the first two quarters of 2008, with a total increase to ATCO Gas' 2007 earnings of $3.2 million.

2008 and 2009 General Rate Application

In November 2007, ATCO Gas filed a general rate application with the AUC for 2008 and 2009 requesting, among other things, increased revenues to recover increased financing, depreciation and operating costs associated with increased rate base in Alberta. ATCO Gas also filed an application requesting interim adjustable rates pending the AUC's decision on the general rate application. In December 2007, ATCO Gas received a decision from the AUC approving interim adjustable rate increases amounting to 50% of ATCO Gas' requested revenue increase. On November 13, 2008, the AUC issued a decision on ATCO Gas' 2008 and 2009 general rate application. The effect of the decision on ATCO Gas' 2008 earnings was not materially different from the impact of the interim rates approved in December 2007. In the decision, the AUC used placeholders for common equity capitalization ratios, 2009 information and technology and customer care and billing costs and income tax amounts. The final amounts for these placeholders will be determined by the AUC in subsequent proceedings. The decision also approved the establishment of deferral accounts to defer the impact of temperature fluctuations on ATCO Gas' revenues after January 1, 2008 (refer to Business Risks – Temperatures section).

Carbon Natural Gas Storage Facility

ATCO Gas owns a 43.5 petajoule natural gas storage facility located at Carbon, Alberta. ATCO Gas has leased the entire storage capacity of the facility to ATCO Midstream. ATCO Gas has taken the position that the facility is no longer required for utility service and should be removed from regulation.

In the process of obtaining AUC approval, a number of significant events have occurred. In July 2004, the AUC initiated a written process to consider its role in regulating the operations of the facility. In June 2005, the AUC issued a decision with respect to this process. In addition to addressing other matters, the decision found that the AUC has the authority, when necessary in the public interest, to direct a utility to utilize a particular asset in a specific manner, even over the objection of the utility. ATCO Gas filed for leave to appeal the decision with the Alberta Court of Appeal.

In October 2005, the AUC established processes to review the use of the facility for utility purposes. A hearing to review the use of the facility for revenue generation was held in April 2006, and a hearing to review the use of the facility for load balancing was held in June 2006. On October 11, 2006, the AUC issued a decision confirming ATCO Gas' position that the facility is no longer required for utility service with respect to the use of the facility for load balancing purposes. The City of Calgary then filed a leave to appeal and a review and variance application of this decision. On November 3, 2008, the AUC denied the City of Calgary's request that it review and vary its decision that the facility is no longer required for utility service with respect to the use of the facility for load balancing purposes.

On February 5, 2007, the AUC issued a decision in which it determined that a legitimate utility use for the facility is that it be used for purposes of generating revenues to offset customer rates. This decision required ATCO Gas to maintain the status quo with respect to the use of the facility including the lease of the entire facility to ATCO Midstream.

On February 26, 2007, ATCO Gas filed for leave to appeal this decision with the Alberta Court of Appeal. The Alberta Court of Appeal granted ATCO Gas' leave to appeal on October 24, 2007. On May 9, 2008, the Alberta Court of Appeal heard the appeal and subsequently issued a decision on May 27, 2008. The Court found that the AUC had erred in law or jurisdiction when it included the Carbon storage facility in rate base for the purpose of generating revenues to offset customer rates. On August 22, 2008, the City of Calgary filed a leave to appeal this decision with the Supreme Court of Canada. On December 4, 2008, the Supreme Court of Canada dismissed the City of Calgary's application for leave to appeal, thus upholding the Alberta Court of Appeal's May 27, 2008 decision.

As a result of the Alberta Court of Appeal's May 27, 2008 decision, ATCO Gas requested and received approval from the AUC to suspend rate riders to customer rates on an interim basis effective July 1, 2008. These riders were approved by the AUC in the past to distribute net revenues related to the facility to customers. As a result of the suspension of the rate riders, ATCO Gas recognized revenues of $6.3 million and earnings of $4.4 million in 2008 for the period July 1, 2008, to December 31, 2008. Due to certain factors, revenues and earnings from this matter for this period are not necessarily indicative of revenues or earnings on an annual basis.

On July 11, 2008, ATCO Gas filed a compliance application with the AUC requesting removal of the facility from the utility rate base and revenue requirement effective April 1, 2005, consistent with the Alberta Court of Appeal decision. Certain aspects of the application were updated on January 15, 2009. This application, in addition to the amounts recognized above, is seeking to recover from customers an additional $30.3 million, excluding interest, related to those amounts refunded to customers over the April 1, 2005, to June 30, 2008, period. This additional $30.3 million and related interest has not been recorded in ATCO Gas' earnings and is pending an AUC decision on the compliance application. On September 29, 2008, the AUC suspended ATCO Gas' compliance application pending the completion of the Utility Asset Disposition Rate Review Proceeding. On October 15, 2008, ATCO Gas filed an application with the Alberta Court of Appeal to direct the AUC to comply with its May 27, 2008, decision. ATCO Gas has withdrawn its October 15, 2008, application to the Alberta Court of Appeal as a result of the AUC recommencing the Carbon proceeding. A pre-hearing conference occurred on December 16, 2008, and on January 9, 2009, the AUC issued a decision establishing a final issues list to remove the Carbon facility from rate base. The AUC has set a proceeding schedule with a hearing currently scheduled to commence on March 16, 2009. At this time it is unknown what the final outcome of these processes will be (refer to Business Risks - Regulated Operations - Carbon Natural Gas Storage Facility section).

As part of the 2008-2009 general rate application, in a compliance application submitted to the AUC on January 19, 2009, ATCO Gas reduced its rate increase applicable to its south customers by $7.6 million related to the production and storage charge that was included in ATCO Gas' rates from January through June 2008 as a result of excluding any costs for the Carbon facility in its general rate application. The impact of this $7.6 million reduction to revenues will be a $5.3 million decrease to ATCO Gas' earnings when a decision on the 2008-2009 general rate application compliance filing is ultimately received.

Deferred Gas Account

ATCO Gas filed an application with the AUC to address, among other things, corrections required to historical transportation imbalances (the process whereby third party natural gas supplies are reconciled to amounts actually shipped in the Company's pipelines) that have impacted ATCO Gas' deferred gas account. In April 2005, the AUC issued a decision resulting in a 15% decrease in the transportation

imbalance adjustments sought by ATCO Gas. The City of Calgary filed a leave to appeal the AUC's decision and ATCO Gas filed a cross appeal of the AUC's decision. On July 7, 2006, the Alberta Court of Appeal issued its decision granting the City of Calgary's leave to appeal on the question of whether the AUC erred in law or jurisdiction in assuming that it had the authority to allow recovery in 2005 of costs relating to prior years. At a hearing on April 13, 2007, the Alberta Court of Appeal declined to consider the City of Calgary's appeal and referred the jurisdictional question back to the AUC. On January 3, 2008, the AUC issued a decision confirming its jurisdiction to approve the prior period adjustment it had approved previously. In February 2008, the City of Calgary filed a leave to appeal the AUC's January 3, 2008, decision with the Alberta Court of Appeal. The hearing for this leave to appeal occurred on December 16, 2008 and a decision is expected in the first quarter of 2009.

ATCO Pipelines

2008 and 2009 General Rate Application

On October 1, 2007, ATCO Pipelines filed a general rate application for the 2008 and 2009 test years requesting increased revenues to recover increased financing, depreciation, and operating costs associated with an increased rate base in Alberta. In November 2007, ATCO Pipelines filed an application requesting interim rates pending the AUC's decision on the general rate application. In December 2007, ATCO Pipelines received a decision from the AUC approving interim adjustable rate increases amounting to 40% of ATCO Pipelines' requested revenue increase. In November 2008, the AUC approved ATCO Pipelines application for revised rates effective December 1, 2008, to collect 60% of ATCO Pipelines requested revenue increase.

In November 2008, ATCO Pipelines filed an application requesting the AUC approve a negotiated settlement with its customers of ATCO Pipelines' 2008 and 2009 revenue requirements. A decision on the application is expected in the first quarter of 2009.

Competitive Proceedings

During 2007, the AUC reinstituted its review of the competitive natural gas pipeline issues under its jurisdiction. This review will address competitive issues between ATCO Pipelines and NOVA Gas Transmission Ltd. (NOVA). This review process is currently suspended to allow ATCO Pipelines and NOVA time to progress their proposed agreement (see below) and to submit the required applications.

Recent Developments

On September 8, 2008, ATCO Pipelines and NOVA announced a proposed agreement to provide natural gas transmission service to their customers. The proposal will allow ATCO Pipelines and NOVA to combine physical assets under a single rates and services structure with a single commercial interface for Alberta customers. Each company would separately manage assets within distinct operating territories within Alberta. This proposal, if approved by the AUC, is expected to end duplicate tolling and operational activities and result in more efficient regulatory processes.

Other Matters

The Company has a number of other regulatory filings and regulatory hearing submissions before the AUC for which decisions have not been received. The outcome of these matters cannot be determined at this time.

Power Generation

Power Generation 2008 **revenues increased** by $116.6 million (15%) over 2007, primarily as a result of higher natural gas fuel purchases recovered on a "no-margin" basis, improved operations and the recognition of insurance proceeds from the Barking outage in ATCO Power's U.K. operations and improved merchant performance in ATCO Power's Alberta generating plants. These increases were partially offset by the impact of lower exchange rates on conversion of revenues to Canadian dollars in ATCO Power's U.K. operations.

Earnings for 2008 were $151.0 million, an **increase** of $16.3 million (12%) over 2007 including the impact of the adjustments identified in the Significant Non-Operating Financial Items section.

Adjusted Earnings were $149.5 million, an **increase** of $31.2 million (26%) over 2007. The primary reasons for the higher Adjusted Earnings were increased availability and the recognition of insurance proceeds from the Barking outage in ATCO Power's U.K. operations and improved merchant performance in ATCO Power's Alberta generating plants. These increases were partially offset by lower exchange rates on conversion of U.K. earnings to Canadian dollars.

Availability of the Power Generation generating plants by geographic region is set forth below:

	For the Year Ended December 31		
	2008	2007	Change to 2008 (2008-2007)
ATCO Power [1]:			
Canada	**94.9%**	96.3%	(1.4%)
U.K.[2]	**87.8%**	83.2%	4.6%
Australia	**98.7%**	94.6%	4.1%
Alberta Power (2000) [1]:			
Canada	**91.8%**	90.2%	1.6%

Notes:

(1) *Generating plant availability will fluctuate due to the timing and duration of outages.*

(2) *The higher availability for 2008 reflects the unplanned outage at the Barking generating plant which commenced on October 25, 2007. The plant returned to service in the first quarter of 2008.*

Unplanned Outage at Barking Generating Plant

On October 25, 2007, ATCO Power's 1,000 MW Barking generating plant in the U.K. experienced an unplanned outage due to failure in a steam turbine generator. On March 6, 2008, ATCO Power announced that the plant had returned to service. This outage reduced the plant capacity to approximately 400 MWs during this period. The financial impact of the failure, prior to the recognition of insurance proceeds, was a decrease to ATCO Power's earnings of $13.4 million (2007 earnings were decreased by $8.6 million and 2008 first quarter earnings were reduced by $4.8 million). Additionally, during the first quarter of 2008, $8.1 million of business interruption and property damage insurance proceeds were recorded ($3.3 million related to 2007 and $4.8 million related to the first quarter of 2008).

The financial impact of the failure, including the recognition of the insurance proceeds, was a decrease to ATCO Power's earnings of $8.6 million in 2007 and an increase to earnings of $3.3 million for 2008, which was recorded in the first quarter of 2008. Discussions are ongoing with insurers and their advisers

to arrive at a final settlement. At this time, an amount for the final insurance settlement cannot be determined.

TXU Europe Settlement

On November 19, 2002, an administration order was issued by an English Court against TXU Europe Energy Trading Limited (TXU Europe) which had a long term "off take" agreement for 27.5% of the power produced by the 1,000 megawatt Barking generating plant in London, England, in which the Company, through Barking Power, has a 25.5% equity interest. Barking Power had filed a claim for damages for breach of contract related to TXU Europe's obligations to purchase 27.5% of the power produced by the Barking generating plant. Following negotiations with the administrators, an agreement was reached with respect to Barking Power's claim.

In settlement of its claim, Barking Power received distributions of £144.5 million (approximately $327 million) in 2005, of which the Company's share was $83.1 million, and distributions of £34.8 million (approximately $71 million) in 2006, of which the Company's share was $18.2 million. Income taxes of approximately $28.5 million relating to the distributions have been paid.

The Company's share of this settlement is being recognized in earnings in equal monthly amounts over the remaining term of the TXU Europe contract to September 30, 2010. Based on the foreign currency exchange rate in effect at December 31, 2008, earnings after income taxes $9.0 million per year have yet to be recognized. These earnings will be dependent upon foreign currency exchange rates in effect at the time that the earnings are recognized.

Other Power Generation Developments

On January 30, 2008, the 150 MW Unit 4 at Alberta Power (2000)'s Battle River generating plant experienced an unplanned outage due to a failure in the unit's generator. The unit returned to service on March 27, 2008. Alberta Power (2000) claimed relief under the force majeure provisions of its PPA. These provisions provide protection for the operator against mechanical failures which last more than forty-two days, except for circumstances where it is found that the operator failed to follow good operating practices. On July 11, 2008, the Balancing Pool notified Alberta Power (2000) that it disagreed with Alberta Power (2000)'s claim for relief under the force majeure provisions of the PPA. Unless settlement on the claim can be reached with the PPA counterparty, it is anticipated that this claim will proceed to arbitration. The cash impact resulting from this outage is approximately $11.8 million, however, due to Alberta Power (2000)'s availability incentive pool deferral account there will be no material earnings impact.

On September 16, 2008, ATCO Power announced that it had completed construction of a 45 MW natural gas-fired generating unit at its Valleyview, Alberta generating plant. The new unit commenced operations in early September, one month ahead of schedule. All of the electricity produced by this peaking facility is sold to the Alberta Power Pool. ATCO Power owns an 80% interest in the plant and ATCO Resources owns 20%.

On November 24, 2008, ATCO Power announced it will design, build, own and operate a two unit 86 MW natural gas-fired simple cycle generating plant in Karratha, Western Australia (the Karratha generating plant). All of the electricity generated will be sold under a 20-year power purchase agreement with Horizon Power, a company owned by the State of Western Australia. The first unit is expected to be completed in the first quarter of 2010. ATCO Power owns a 100% interest in the plant.

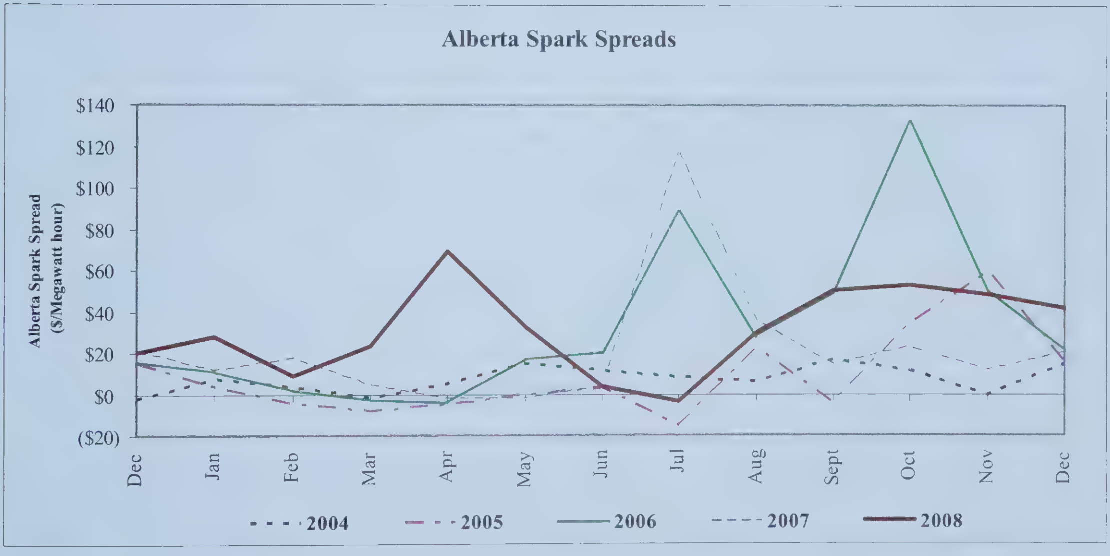
On January 28, 2009, ATCO Power entered into an Australian $100 million credit facility with the Commonwealth Bank of Australia. The facility term is for construction plus five years. The interest rate

during construction will be 5.71% and the rate during operation will be 6.16%. The funds will be used to finance the design and construction of the Karratha generating plant.

The majority of ATCO Power's electricity sales to the Alberta Power Pool are from natural gas-fired generating plants, and as a result earnings are affected by natural gas prices and Alberta Power Pool prices. Alberta Power Pool electricity prices averaged $89.95 per MWh in 2008, compared to average prices of $66.95 per MWh in 2007. Natural gas prices averaged $7.73 per GJ, compared to average prices of $6.10 per GJ in 2007. These electricity and natural gas prices resulted in an average spark spread of $32.00 per MWh in 2008, compared to $21.22 per MWh in 2007.

Changes in spark spread affect the results of approximately 442 MW of plant capacity owned in Alberta by ATCO Power and Alberta Power (2000) out of a total Alberta-owned capacity of approximately 1,745 MWs and approximately 70 MW of plant capacity owned in the U.K. by ATCO Power out of a total U.K.-owned capacity of approximately 262 MW and a worldwide owned capacity by ATCO Power and Alberta Power (2000) of approximately 2,510 MW.

The following chart demonstrates the volatility of Alberta spark spreads experienced by ATCO Power for the period of December 2003 to December 2008.



The Company's merchant power sales are affected by volatility in power and natural gas prices caused by market forces such as fluctuating supply and demand for electricity. The Company manages this volatility through its adoption of asset optimization strategies for bidding its merchant power into both the Alberta and U.K. power markets.

Alberta Power (2000)

The generating plants of Alberta Power (2000) were regulated by the AUC until December 31, 2000, but are now governed by legislatively mandated PPAs that were approved by the AUC. These plants are included in regulated operations primarily because the PPAs are designed to allow the owners of generating plants constructed before January 1, 1996, to recover their forecast fixed and variable costs and to earn a return at the rate specified in the PPAs. Each plant will become deregulated upon the earlier of one year after the expiry of its PPA or a decision to continue to operate the plant. For PPAs expiring prior to 2019, Alberta Power (2000) has one year after the expiry of a PPA to determine whether to

decommission the generating plant in order to fully recover plant decommissioning costs or to continue to operate the plant and be responsible for decommissioning costs. For PPAs expiring after 2018, decommissioning costs are the responsibility of the plant owner. Each PPA is to remain in effect until the earlier of the last day of the estimated life of the related generating plant or December 31, 2020.

Over 99% of the electricity generated by Alberta Power (2000) is sold pursuant to PPAs. Under the PPAs, Alberta Power (2000) is required to make the generating capacity for each generating unit available to the purchaser of the PPA for that unit. In return, Alberta Power (2000) is entitled to recover its forecast fixed and variable costs for that unit from the PPA purchaser, including a rate of return on common equity equal to the long term Government of Canada bond rate plus 4.5% based on a deemed common equity ratio of 45%. Many of the forecast costs will be determined by indices, formulae or other means for the entire period of the PPA. Alberta Power (2000)'s actual results will vary and depend on performance compared to the forecasts on which the PPAs were based. The return on common equity rate used in its PPA tariff calculations for Alberta Power (2000) was 8.88% in 2008 and 8.65% for 2007. The rate of return on common equity for 2009 is 8.64%.

Under the terms of the PPAs, Alberta Power (2000) is subject to an incentive/penalty regime related to generating unit availability. Incentives are payable by the PPA counterparties for availability in excess of predetermined targets, and penalties are payable by Alberta Power (2000) when the availability targets are not achieved.

Accumulated incentives in excess of accumulated penalties are deferred. For any of the individual PPAs, should accumulated incentives plus estimated future incentives exceed accumulated penalties plus estimated future penalties, the excess will be amortized to revenues on a straight-line basis over the remaining term of the PPAs. Should accumulated penalties plus estimated future penalties exceed accumulated incentives plus estimated future incentives, the shortfall will be expensed in the year the shortfall occurs.

During 2008, the deferred availability incentive account increased by $19.5 million to $61.3 million at December 31, 2008, due to additional availability incentives received for plant availability in excess of amortization and planned outages. During 2008, the amortization of deferred availability incentives, recorded in revenues, increased by $0.8 million to $12.6 million.

H.R. Milner Generating Plant

In 2001, Alberta Power (2000) and the Balancing Pool entered into an agreement which gave the Balancing Pool control of the 150 megawatt, coal-fired H.R. Milner generating plant effective January 1, 2001 and the right to sell it until September 30, 2003, failing which the rights to control the generating plant would revert to Alberta Power (2000). In return, Alberta Power (2000) was paid $63.5 million, the net book value of the generating plant and coal inventory. Alberta Power (2000) operated the generating plant under a cost of service contract with the Balancing Pool. On August 6, 2003, the Balancing Pool announced that it had entered into an agreement for the sale of plant. Alberta Power (2000) extended its cost of service contract until January 29, 2004, when the plant was sold by the Balancing Pool to a third party.

In 2006, the CRA issued a reassessment for Alberta Power (2000)'s 2001 taxation year which treated the proceeds received from the sale of the H.R. Milner generating plant to the Balancing Pool as income rather than as a sale of an asset. The impact of the reassessment was a $12.4 million increase in interest and income tax expense, a $12.4 million decrease in earnings and a $28.8 million payment associated with the tax and interest assessed. The Company disagreed with the CRA's position and appealed the reassessment to the Tax Court of Canada. Due to the uncertainty as to whether the reassessment would ultimately be resolved in the Company's favour, the Company made the $28.8 million payment and

reduced earnings by $12.4 million in 2006. The Tax Court of Canada is scheduled to hear the Company's appeal in March 2009. The Company is unable to predict the outcome at this time.

Greenhouse Gas Emissions

In 2007, Alberta Power (2000) began to record GHG emissions fees recovered from its customers in accordance with the PPAs which cover costs of recent changes in environmental laws (refer to Business Risks - Environmental Matters section). As the collection of the majority of these fees is on a flow through basis, there is minimal impact on the earnings of Alberta Power (2000).

In the fourth quarter of 2008, the Company recognized $3.0 million in earnings from carbon offsets generated by ATCO Power's Oldman River hydro generating plant during the period from July 1, 2003, to December 31, 2008. The offsets were determined in accordance with the government of Alberta's protocol for hydro generating plants.

Global Enterprises

Global Enterprises **revenues increased** by $118.1 million (18%) from 2007. Items that increased revenues include increased business activity in ATCO Frontec's operations and higher volumes of natural gas purchased for others in ATCO Midstream. These increases were partially offset by lower storage revenues due to the timing and demand of natural gas storage capacity sold and lower storage fees in ATCO Midstream.

Earnings for 2008 were $126.9 million, an **increase** of $16.9 million (15%) over 2007, including the impact of the adjustments identified in the Significant Non-Operating Financial Items section.

In 2008, **Adjusted Earnings** were $122.7 million, an **increase** of $14.1 million (13%) over 2007. The primary reasons for the higher Adjusted Earnings were increased business activity in ATCO Frontec's operations and higher margins for NGL extraction in ATCO Midstream. These increases were partially offset by lower storage fees in ATCO Midstream.

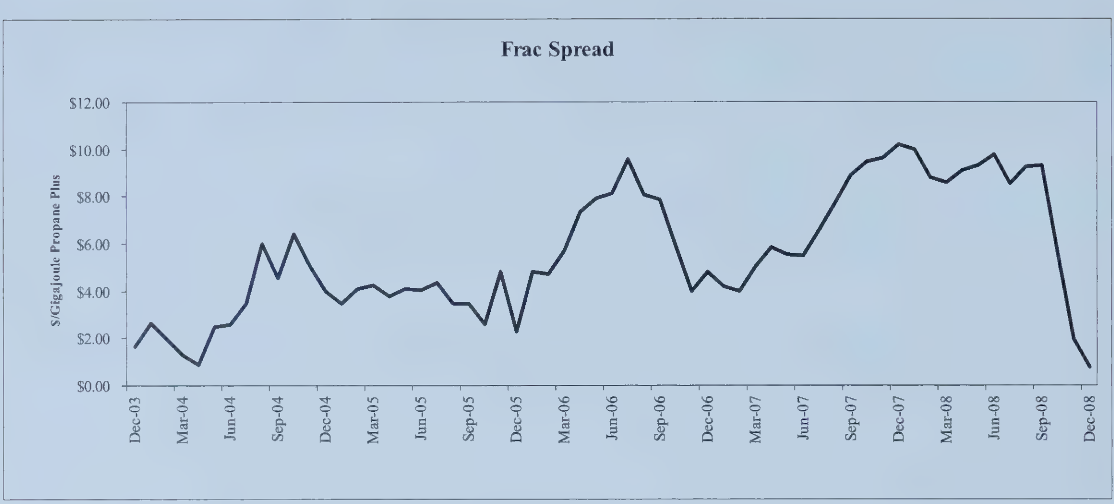
ATCO Midstream

ATCO Midstream provides non-regulated natural gas gathering and processing, NGL extraction, and natural gas storage services to natural gas producers.

NGL Extraction Operations

A portion of ATCO Midstream's revenues is derived from the extraction of NGL from natural gas and the marketing of NGL products under supply or marketing contracts. ATCO Midstream owns a net working interest of 411 million cubic feet per day in its NGL extraction plants.

ATCO Midstream's NGL extraction operations involve the extraction of NGL from natural gas and the replacement (on a heat content equivalent basis) of the NGL extracted with shrinkage gas. For Propane Plus, the difference between the price of natural gas and the value of the liquids extracted is commonly referred to as the frac spread. Frac spreads vary with fluctuations in the price of natural gas and the prices of the applicable liquid extracted. Frac spreads can be volatile, as shown in the following graph, which illustrates monthly frac spreads during the period of December 2003 to December 2008.



Note:
(1) *The above chart represents measurements of frac spreads in Alberta, as reported by an independent consultant.*

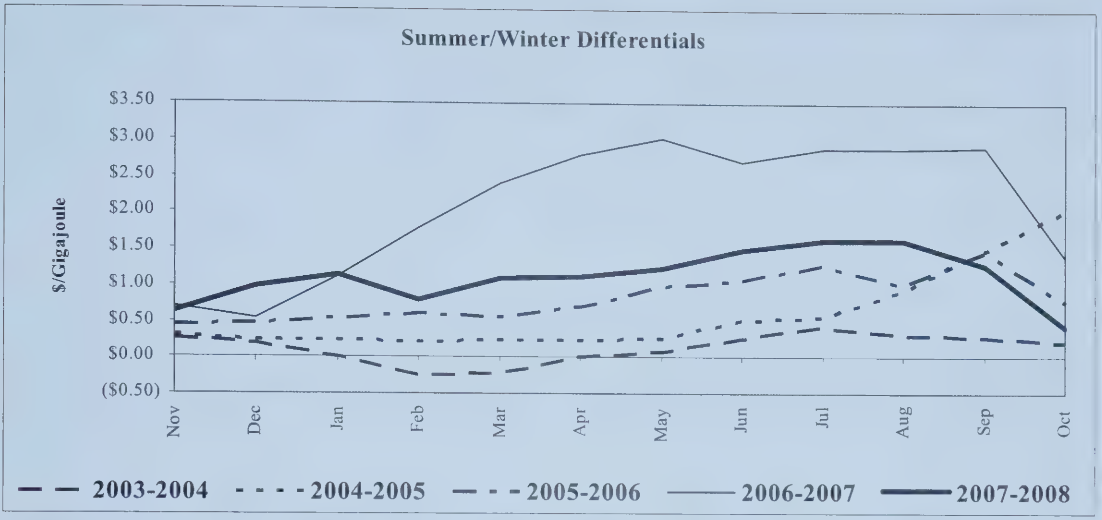
Lower prices for natural gas liquids were the primary cause of the decreased frac spread in the fourth quarter of 2008. Natural gas liquids prices are impacted by oil prices and the significant decrease in oil prices was the primary cause for lower NGL prices.

Fluctuations in frac spreads affect ATCO Midstream's earnings and cash flow from operations. A $1.00 change in the average annual frac spread impacts annual earnings by approximately $6 million.

Storage Operations

The majority of ATCO Midstream's natural gas storage revenues come from seasonal differences (summer/winter) in the price of natural gas (price differentials). Recognition of ATCO Midstream's revenues is determined through the terms of the contractual arrangements.

Summer/winter natural gas price differentials can be volatile, as shown in the following graph, which illustrates a range of seasonal spreads experienced during the storage periods from 2004-2005 to 2008-2009. Price differentials at any point in time may not always be indicative of the storage revenue and earnings for the same period due to the types of contracts and the timing of the revenue recognition associated with these contracts.



ATCO Midstream faces risks associated with changes to seasonal natural gas commodity price differentials. To mitigate this risk, ATCO Midstream maintains portfolios of varied contracts, delivery terms, capacities and customers for its storage operations.

Recent Developments

On Nov. 17, 2008, ATCO Midstream announced the purchase of IPL Holdings Inc. (IPLH). IPLH, Inuvialuit Petroleum Corporation and AltaGas Utility Group Inc. are partners in the Ikhil joint venture and each owns a one-third interest in Inuvik Gas Ltd. The Ikhil joint venture owns and operates two producing natural gas wells and gas gathering and processing facilities in the Mackenzie delta region of the Northwest Territories and a 50 kilometre pipeline connecting the facilities to the town of Inuvik. Inuvik Gas Ltd., the sole distributor of natural gas in Inuvik, serves more than 850 customers.

ATCO Frontec

ATCO Frontec, through its own operations and through a number of joint ventures, provides project management and technical services for customers in the resource, defence and telecommunications sectors.

Activities include:

- the operation and maintenance of the North Warning System, Alaska Radar System and various remote sites for Northwestel Inc. in northern Canada;
- accommodations for oil sands workers at the Creeburn Lake and Barge Landing Lodges north of Fort McMurray, Alberta;
- construction and support services for NATO, United Nations and the Swedish Armed Forces in Afghanistan and eastern Europe;
- airport operation and maintenance in Canada and Afghanistan;
- operation and maintenance of a bulk fuel storage and distribution facility in Iqaluit, Nunavut; and
- a wide variety of services and business activities in numerous locations across Canada.

A number of the Canadian operations are conducted with aboriginal partners.

The following is a summary of the principal contracts which provide significant contributions to ATCO Frontec's earnings:

Contract	Customer	Start Date	Completion Date	Possible Extension [1]
Alaska Radar System [2]	U.S. Department of Defense	Oct. 2004	Sep. 2009	2014
North Warning System [2]	Department of National Defense	Sep. 2001	Sep. 2011	-
Iqaluit Fuel Contract [2]	Government of Nunavut	Jun. 2007	Nov. 2012	2017
Stabilization Force Organization	NATO	Feb. 2004	Dec. 2009	-
Kabul International Airport	NATO	Feb. 2005	Aug. 2009	Dec. 2009
NATO Flight Training	NATO	Jun. 2000	May 2020	-
Kandahar Projects	NATO	Sep. 2007	Sep. 2010	2012
Creeburn Lake Lodge [2]		April 2008	-	-
Barge Landing Lodge [2]	Suncor Energy Inc.	July 2008	Jun. 2009	-
	Albian Sands Energy Inc.	Oct. 2008	Mar. 2010	Mar. 2011

Notes:
(1) *The contract may be extended at the option of the customer.*
(2) *Joint venture with aboriginal partners.*

Recent Developments

On April 14, 2008, ATCO Frontec announced that the first phase of the 500-room Creeburn Lake Lodge north of Fort McMurray, Alberta had commenced operations. The Creeburn Lake Lodge accepts clients on a nightly, weekly or monthly basis. Due to recent declines in world oil prices and the cancellation and delay of a number of oil sands projects in Alberta, ATCO Frontec has decided not to proceed with the expansion of the Creeburn Lake Lodge at this time.

On April 28, 2008, ATCO Frontec and its partner, the Fort McKay First Nation, announced that they had been selected by Suncor Energy Inc. (Suncor) to create and operate the Barge Landing Lodge, a 1,148-room accommodation complex to support oil sands development north of Fort McMurray. ATCO Structures supplied the rooms in modular units. Operations commenced in July 2008. On August 18, 2008, a 603-room expansion was announced under the existing joint venture with the Fort McKay First Nation for Albian Sands Energy Inc. (Albian). Operations for the expansion commenced in October 2008. The Albian contract will expire in March 2010 unless extended for an additional 12 months at the option of Albian, and the Suncor contract will expire in June 2009.

ATCO I-Tek

ATCO I-Tek is engaged in the development, operation and support of information systems and technologies.

ATCO I-Tek provides billing services, payment processing, credit, collection and call centre services to its clients. ATCO I-Tek currently provides such services to Direct Energy for its regulated retail and competitive energy supply businesses in Alberta. In addition, ATCO I-Tek also supplies distribution-related billing and customer care services to ATCO Gas and ATCO Electric. In 2008, ATCO I-Tek's call centre was named the top customer service provider in the North American energy sector by Service Quality Measurement Group Inc. for the third year in a row.

Direct Energy has entered into a 10 year contract effective May 4, 2004, with ATCO I-Tek to provide billing and call centre services to ensure continued quality customer service. Direct Energy has the ability to terminate this contract after the fifth anniversary upon immediate payment of termination fees which decline over the remaining term of the contract. Based upon current customer counts and service levels and a 10 year contract, revenues are estimated to be between $400-$500 million over the term of the contract.

Corporate and Other

Earnings for 2008 were $(12.7) million, a **decrease** of $15.8 million (510%) over 2007, including the impact of the adjustments identified in the Significant Non-Operating Financial Items section.

In 2008, **Adjusted Earnings** were $(12.8) million, a **decrease** of $7.2 million (129%) over 2007. The primary reasons for the lower Adjusted Earnings in 2008 were lower rates of interest earned on lower cash balances.

Liquidity and Capital Resources

A major portion of the Company's operating income and funds generated by operations is generated from its utility operations. Canadian Utilities and its wholly owned subsidiary, CU Inc., use short term bank loans and commercial paper borrowings to provide flexibility in the timing and amounts of long term financing.

SUMMARY OF CASH FLOW	For the Year Ended December 31		
($ millions)	**2008**	2007	Change to 2008 (2008-2007)
Cash position, beginning of period	**747.2**	798.8	(6%)
Cash provided by (used in)			
Operating activities	**791.8**	706.9	12%
Investing activities	**(813.1)**	(642.1)	27%
Financing activities	**12.0**	(98.8)	112%
Foreign currency impact on cash balances	**(11.3)**	(17.6)	36%
Cash position, end of period	**726.6**	747.2	(3%)

OPERATING ACTIVITIES

Cash flow from operations increased by 12% in 2008, primarily due to increases in funds generated by operations, partially offset by changes in non-cash working capital. **Funds generated by operations increased** by 11% in 2008, primarily due to higher cash earnings and increased deferred availability incentives in Alberta Power (2000).

INVESTING ACTIVITIES

In 2008, **cash used in investing activities increased** 27%, primarily due to higher capital expenditures in 2008, partially offset by higher contributions by utility customers for extensions to plant, changes in non-cash working capital and non-current deferred electricity costs. **Capital expenditures increased** by $310.1 million, primarily due to increased investment in regulated electric and natural gas distribution and transmission projects.

Capital Expenditures	**For the Year Ended December 31**		
($ millions)	**2008**	2007	Change to 2008 (2008-2007)
Utilities	**869.4**	588.9	48%
Power Generation	**75.8**	49.2	54%
Global Enterprises	**56.2**	62.7	(10%)
Corporate and Other	**9.5**	-	-
	1,010.9	700.8	44%

Capital expenditures to maintain capacity, meet planned growth, and fund future development activities are expected to be approximately $1.1 billion in 2009, an increase of 9% from 2008. The majority of these expenditures relate to the Utilities segment. For the 2009 to 2011 period, capital expenditures in the Utilities segment are expected to be $2.0 billion and, depending on infrastructure spending, could be as much as $4.0 billion over the next three years.

The planned capital expenditures for the Utilities segment are based on the following assumptions:

- the AESO projects approved in principle by the AUC will proceed as currently scheduled;
- the remaining planned capital expenditures in the Utilities segment are required to maintain capacity and meet planned growth in the Company's service areas. These expenditures are consistent with the anticipated growth in the Alberta economy and in the Company's service areas; and
- The regulatory system in Alberta will remain substantially unchanged.

In the opinion of the Company, these assumptions are reasonable, but no assurance can be given that these assumptions will prove to be correct.

ATCO Electric, ATCO Gas and ATCO Pipelines are regulated primarily by the AUC, which administers acts and regulations covering such matters as rates, financing, accounting, construction, operation and service area. The AUC approves customer rates based on the revenue required to recover estimated costs of service, including a fair return on rate base, estimated operating expenses, depreciation and taxes, all in respect of a future test year. Return on rate base is designed to meet the cost of interest on long term debt and dividends on preferred shares and to provide the shareowners with a reasonable opportunity to earn a fair return on their investment.

ATCO Electric, ATCO Gas and ATCO Pipelines are subject to the normal risks faced by companies that are regulated. These risks include the approval by the AUC of customer rates that permit a reasonable opportunity to recover on a timely basis the estimated costs of providing service, including a fair return on rate base. In addition, these risks include the disallowance of capital expenditures incurred if the AUC determines that such costs were not prudently incurred. This risk is mitigated by the inclusion of capital expenditures in general rate applications approved by the AUC. Furthermore, all major electric transmission projects assigned by the AESO to ATCO Electric are required to be approved by the AUC prior to commencing construction.

Tightness in labour and materials markets in Alberta in recent years has resulted in substantial growth in costs of many construction projects, and while the Company attempts to mitigate the risk of delays and cost overruns by careful planning and entering into long term contracts when possible, there can be no assurance that significant cost overruns or delays will not occur.

On September 9, 2008, ATCO Electric announced it had entered into an agreement with UK-based Balfour Beatty and Australia-based United Group Limited for engineering, construction, procurement and project management services to provide these services for required capital projects in the extremely tight labour market for such services available in Alberta. Individual projects assigned pursuant to this agreement will be jointly estimated and a target project cost agreed to before construction commences. The agreement provides ATCO Electric full discretion to assign or remove projects on an individual basis. Projects will be undertaken with a full disclosure to the AUC of actual costs, with any savings or overruns relative to target project costs shared equally.

FINANCING ACTIVITIES

In 2008, the Company had **net debt increases** of $173.5 million. **Issuance** of debt included $200.0 million of 5.580% Debentures due May 2038, $125.0 million of 5.563% Debentures due May 2028 and $45.7 million of other long term debt. **Redemptions** were comprised of $100.0 million of 6.97% Debentures which matured in June 2008, $12.0 million of other long term debt and $85.2 million of non-recourse long term debt.

In 2008, the Company had **no issues or redemptions** of equity preferred shares, compared to an issue of $115 million of equity preferred shares by a subsidiary and a redemption of $126.5 million of equity preferred shares in 2007.

In 2008, there were **no purchases** of Class A Shares under its normal course issuer bids, a decrease of $8.0 million from 2007. In 2008, **issues** of Class A Shares due to stock option exercises were $5.0 million, an increase of $3.4 million over 2007. In 2008, **net issues** were $5.0 million, an increase of $11.4 million over the corresponding period in 2007.

On May 23, 2007, the Company commenced a normal course issuer bid for the purchase of up to 5% of the outstanding Class A Shares. The bid expired on May 22, 2008. From May 23, 2007, to May 22, 2008, 157,800 shares were purchased, all of which were purchased in 2007. On May 23, 2008, the Company commenced a new normal course issuer bid for the purchase of up to 3% of the outstanding Class A Shares. The bid will expire on May 22, 2009. No shares have been purchased from May 23, 2008 to February 13, 2009.

Total **dividends paid to Class A and Class B share owners increased** by 6% to $166.8 million over 2007. At their meeting in the first quarter of 2008, the Board of Directors increased the quarterly dividend by $0.0175 to $0.3325 per share over the corresponding periods in 2007. The Company has increased its annual common share dividend each year since its inception as a holding company in 1972. At their meeting in the first quarter of 2009, the Board of Directors increased the quarterly dividend by $0.02 to $0.3525. The payment of any dividend is at the discretion of the Board of Directors and depends on the financial condition of the Company and other factors.

FOREIGN CURRENCY TRANSLATION

Foreign currency translation impacted the Company's cash position by $(11.3) million as a result of changes in U.K. and Australian exchange rates used for balance sheet translations.

SHORT TERM INVESTMENT POLICY

The Company has a long-standing policy not to invest any of its cash balances in asset-backed securities; consequently, the recent turmoil in the asset-backed commercial paper market has had no impact on the Company. Cash and short term investment credit risk is reduced by investing in instruments issued by credit worthy financial institutions and in federal government issued short term investments.

LINES OF CREDIT

At December 31, 2008, the Company had the following credit lines that enable it to obtain funding for general corporate purposes.

($ millions)	Total	Used	Available
Long term committed	326.0	48.2	277.8
Short term committed	600.0	54.1	545.9
Uncommitted	99.1	28.1	71.0
Total	1,025.1	130.4	894.7

The Company's long term committed lines of credit include:

- A $200 million unsecured revolving extendible term credit facility of Canadian Utilities established in 1999 with a syndicate of Canadian chartered banks. This facility will expire in June 2013, unless extended at the option of the lenders; and
- A $100 million unsecured revolving extendible term credit facility of ATCO Midstream established in 1999 with a syndicate of Canadian chartered banks and financial institutions. The facility will expire in August 2013, unless extended at the option of the lenders.

The Company's short term committed lines of credit consist of:

- A $300 million unsecured revolving extendible credit facility of CU Inc. established in 1999 with a syndicate of Canadian chartered banks. This facility is used as a backstop for CU Inc.'s commercial paper program and for occasional issues of letters of credit. The facility will expire in June 2009, unless extended at the option of the lenders; and
- A $300 million unsecured revolving extendible credit facility of Canadian Utilities established in 1999 with a syndicate of Canadian chartered banks. This facility is used as a backstop for Canadian Utilities' commercial paper program. This facility will expire in June 2009, unless extended at the option of the lenders.

The Company's uncommitted lines of credit are primarily used by its subsidiaries for liquidity purposes and for issues of letters of credit. Most of these facilities are unsecured, but some are secured by charges over assets of particular subsidiaries.

The amount and timing of future financings will depend on market conditions and the specific needs of the Company.

CONTRACTUAL OBLIGATIONS

Contractual obligations for the next five years and thereafter are as follows:

	Payments Due by Period				
($ millions)	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
Long term debt	2,877.0	142.7	247.3	182.0	2,305.0
Non-recourse long term debt	462.4	44.8	91.4	82.2	244.0
Interest expense [1]	2,852.3	220.9	385.3	340.7	1,905.4
Operating leases	132.5	21.6	37.2	24.3	49.4
Purchase obligations:					
ATCO Gas natural gas purchase contracts [2]	2.0	0.4	0.8	0.8	-
Alberta Power (2000) coal purchase contracts [3]	606.9	50.2	104.0	144.0	308.7
ATCO Power natural gas fuel supply contracts [4]	99.6	46.3	47.9	5.4	-
Alberta Power (2000), ATCO Power operating and maintenance agreements [5]	136.0	18.2	35.8	33.1	48.9
Capital Expenditures [6]	137.8	133.5	4.3	-	-
Derivatives[7]	22.7	5.1	7.8	4.3	5.5
Other	2.9	0.9	1.2	0.6	0.2
Total	7,332.1	684.6	963.0	817.4	4,867.1

Notes:

(1) *Interest payments on floating rate debt that has not been hedged have been estimated using rates in effect at December 31, 2008. Interest payments on debt that has been hedged have been estimated using the hedged rates.*

(2) *ATCO Gas has ongoing obligations to purchase fixed quantities of natural gas from various gas producers at market prices that are in effect at the time the quantities are purchased. These obligations relate primarily to operational contracts pertaining to the Carbon natural gas storage facility, which continues to be subject to AUC regulation. Some of these obligations are for the life of the gas reserves. The estimated value of these purchase obligations is based on the market price of natural gas in effect on December 31, 2008, and assumes a remaining life of 10 years for the gas reserves commencing January 1, 2004. Direct Energy has agreed to purchase the natural gas purchased under these contracts at the prices paid by ATCO Gas.*

(3) *Alberta Power (2000) has fixed price long term contracts to purchase coal for its coal-fired generating plants. These costs are recoverable pursuant to the PPAs.*

(4) *ATCO Power has various contracts to purchase natural gas for certain of its natural gas-fired generating plants. ATCO Power has long term offtake agreements with the purchasers of the electricity to recover 78% of these costs. The balance of 22%, related to ATCO Power's Barking generating plant, is recovered through merchant sales in the U.K. electricity market. The ATCO Power merchant component of its generating plants in Alberta do not have any long term contracts to purchase natural gas.*

(5) *Alberta Power (2000) and ATCO Power have various contracts with suppliers to provide operating and maintenance services at certain of their generating plants.*

(6) *Various contracts to purchase goods and services with respect to capital expenditure programs.*

(7) *Payments on outstanding derivatives have been estimated using rates in effect at December 31, 2008.*

NET CURRENT AND LONG TERM FUTURE INCOME TAXES

Net current and long term future income taxes of $158.6 million at December 31, 2008, are attributable to differences between the financial statement carrying amounts of assets and liabilities and their tax bases. These differences result primarily from recognizing revenue and expenses in different

years for financial and tax reporting purposes. Future income taxes will become payable when such differences are reversed through the settlement of liabilities and realization of assets.

BASE SHELF PROSPECTUS

On May 16, 2008, CU Inc. filed a **base shelf prospectus** which permits CU Inc. to issue up to an aggregate of $1,500.0 million of debentures over the twenty-five month life of the prospectus. As at December 31, 2008, the following debentures had been issued:

- on May 26, 2008, CU Inc. issued $200.0 million of 5.580% Debentures due May 26, 2038, at a price of 100 to yield 5.580%, and
- on May 26, 2008, CU Inc. issued $125.0 million of 5.563% Debentures due May 26, 2028, at a price of 100 to yield 5.563%.

The proceeds of these issues were advanced to ATCO Electric, ATCO Gas and ATCO Pipelines to be used to fund capital expenditures, to repay indebtedness and for other general corporate purposes.

Share Capital

The equity securities of the Company consist of Class A Shares and Class B Shares.

At February 13, 2009, the Company had outstanding 83,757,894 Class A Shares, 41,756,926 Class B Shares and options to purchase 1,233,550 Class A Shares.

CLASS A NON-VOTING SHARES AND CLASS B COMMON SHARES

The owners of the Class A shares and the Class B shares are entitled to share equally, on a share for share basis, in all dividends declared by the Company on either of such classes of shares as well as the remaining property of the Company upon dissolution. The owners of the Class B shares are entitled to vote and to exchange at any time each share held for one Class A share.

If a take-over bid is made for the Class B shares which would result in the offeror owning more than 50% of the outstanding Class B shares and which would constitute a change in control of the Company, owners of Class A shares are entitled, for the duration of the bid, to exchange their Class A shares for Class B shares and to tender such Class B shares pursuant to the terms of the take-over bid. Such right of exchange is conditional upon the completion of the take-over bid giving rise to the right of exchange, and if the take-over bid is not completed, then the right of exchange shall be deemed never to have existed. In addition, owners of the Class A shares are entitled to exchange their shares for Class B shares of the Company if ATCO Ltd., the present controlling share owner of the Company, ceases to own or control, directly or indirectly, more than 10,000,000 of the issued and outstanding Class B shares of the Company. In either case, each Class A share is exchangeable for one Class B share, subject to changes in the exchange ratio for certain events such as a stock split or rights offering.

Of the 6,400,000 Class A non-voting shares authorized for grant in respect of options under Canadian Utilities Limited's stock option plan, 2,972,700 Class A non-voting shares are available for issuance at December 31, 2008. Options may be granted to directors, officers and key employees of Canadian Utilities Limited and its subsidiaries at an exercise price equal to the weighted average of the trading price of the shares on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant. The vesting provisions and exercise period (which cannot exceed 10 years) are determined at the time of grant. As of February 13, 2009, options to purchase 1,233,550 Class A shares were outstanding.

Business Risks

FINANCIAL MARKETS

Significant challenges are currently being experienced in domestic and international financial markets. These challenges are having an impact on the ability of certain borrowers to finance existing operations and capital programs. As discussed elsewhere in this MD&A, the Utilities Business Group has a capital program of $2.0 billion and, depending on infrastructure spending, could be as much as $4.0 billion over the next three years. The Company completed a $325 million debenture issue in May 2008 to fund the 2008 portion of the Utilities Business Group's capital program and to fund scheduled maturities of previous debenture issues. On January 28, 2009, ATCO Power entered into an Australian $100 million credit facility with the Commonwealth Bank of Australia to finance the design and construction of the Karratha generating plant located in Western Australia. In addition, the Company has cash balances of approximately $0.7 billion and available committed and uncommitted lines of credit of approximately $0.9 billion which can be utilized for general corporate purposes.

While the current financial situation has not directly impacted the Company's ability to fund capital projects and ongoing operations, future borrowing may be impacted by these financial markets through increased carrying costs and the ability to raise debt and equity capital. The Company is unable to determine what future changes in the financial markets could occur and how these changes could affect the Company. In addition, the deterioration in the domestic and international economic activity may impact the operations of the Company.

COMMODITY PRICES

Commodity prices, particularly oil and natural gas prices, have fallen significantly since September 2008. These lower prices have had an impact on the Company's operations, particularly the lower frac spreads on ATCO Midstream's NGL business. The Company is unable to determine what future changes in commodity markets could occur and how these changes could affect the Company.

PENSION PLANS

Recent declines in stock and bond markets have resulted in a reduction in the value of the Company's defined benefit pension plans, creating a pension plan deficit that may require the Company to make contributions to the pension plans commencing in 2009.

Employees are required to contribute a percentage of their salary to the registered defined benefit pension plans. The Company is required to provide the balance of the funding, based on triennial actuarial valuations, necessary to ensure that benefits will be fully provided for at retirement. Based on the most recent actuarial valuation for funding purposes as of December 31, 2006 the Company is continuing a contribution holiday that began on April 1, 1996 for all but one of the registered pension plans; commencing in 2007, the Company is required to make annual contributions of approximately $0.7 million to cover the unfunded liability of that plan. The next actuarial valuation for funding purposes is required as of December 31, 2009. The government of Alberta has issued a white paper which, if it becomes law, would require an actuarial valuation to be filed as at December 31, 2008, for those plans that wish to continue their contribution holidays in 2009. Depending on the outcome of the full actuarial valuation, current service contributions may be required to resume in 2009.

ENVIRONMENTAL MATTERS

The Company's operating subsidiaries and the industries in which they operate are subject to extensive federal, provincial and local environmental protection laws concerning emissions to the air, discharges to surface and subsurface waters, land use activities and the handling, manufacturing, processing, use, emission and disposal of materials and waste products.

On March 10, 2008, the government of Canada released details of its draft regulatory framework originally announced on April 26, 2007. Electricity sector companies must achieve an initial GHG reduction in 2010 of 18% from their company-wide emission intensity, with a 2% continuous improvement required annually thereafter. New facilities (2004 or later) are allowed a 3-year grace period after which they must improve emission intensity by 2% per year below the clean fuel standard. For cogeneration facilities, steam production GHG emissions are subjected to the reduction target and electricity production emissions are compared to a deemed emission target. Compliance may be achieved by reduction or capture, limited investment in a technology fund, emission credit trading, purchase of offset credits, *Kyoto Protocol Clean Development Mechanisms* (maximum 10%) and very limited opportunity for early action credits. The government reiterated that it intends to implement fixed emission caps in the 2020 to 2025 time period. A draft regulation has yet to be released.

The federal government also announced plans to set targets to regulate air pollutants (sulphur dioxide, nitrogen oxides, particulate matter, volatile organic compounds and mercury) from industrial sources by 2015. Air pollutant elements will be added to the draft regulations once the regulatory framework for air pollutants has been finalized.

Alberta legislation requires large emitters to reduce GHG emission intensities by 12% starting July 1, 2007. Baseline emission values for Alberta Power (2000)'s and ATCO Power's facilities have been established and compliance reports with compensation for 2007 GHG obligations were submitted to Alberta Environment on March 31, 2008. For Alberta Power (2000)'s coal-fired units, the PPA counterparties have reimbursed Alberta Power (2000) for amounts it paid to Alberta Environment for its 2007 GHG obligations.

Alberta regulation requires coal-fired generating plant operators, including Alberta Power (2000), to monitor mercury emissions and target a capture of at least 70% of the mercury in the coal commencing January 1, 2011. A full scale test at the Battle River generating plant Unit 5 is underway to test the mercury control method to ensure the capture objective can be met.

It is anticipated that the PPAs will allow Alberta Power (2000) to recover most of the costs associated with complying with both the federal and Alberta regulations during the PPA term.

Due to lower emissions per unit of output, ATCO Power's gas-fired generating units have minimal exposure to changes in GHG regulations, and therefore it is anticipated that there will not be a material impact from complying with the Alberta regulations.

In November 2008, the federal government signaled its intention to pursue a North America wide emissions trading program. The government has not released details of this proposed emissions trading system and it has remained non-committal as to whether it will continue with the implementation of the legislation. ATCO Power continues to monitor these developments and the impact of complying with the federal regulations.

REGULATED OPERATIONS

Regulated operations are conducted by Canadian Utilities' wholly owned subsidiary CU Inc., which in turn has the following subsidiaries: ATCO Electric and its subsidiaries, ATCO Gas, ATCO Pipelines, and CU Water. Alberta Power (2000)'s two largest generating plants are also considered regulated operations because they are governed by legislatively mandated PPAs, approved by the AUC.

ATCO Electric, ATCO Gas, ATCO Pipelines and CU Water are subject to the normal risks faced by companies that are regulated. These risks include the approval by the AUC of customer rates that permit a reasonable opportunity to recover on a timely basis the estimated costs of providing service, including a fair return on rate base. In addition, these risks include the disallowance by the AUC, of costs incurred. The Company's ability to recover the actual costs of providing service and to earn the approved rates of return depends on achieving the forecasts established in the rate-setting process.

Carbon Natural Gas Storage Facility

ATCO Gas leases the entire storage capacity of the Carbon natural gas storage facility to ATCO Midstream at AUC approved placeholder rates. Additionally, at the AUC's direction ATCO Gas has been using these revenues to offset customer rates. On February 5, 2007, the AUC issued a decision that left in question these placeholder rates and the effect that these placeholder rates would have on future ATCO Gas revenues and customer rates. Subsequent to a decision received from the Alberta Court of Appeal on May 27, 2008, which set aside the February 5, 2007 AUC decision, ATCO Gas requested, and received, approval from the AUC to suspend rate riders relating to the distribution of revenues and the costs associated with the Carbon operations (refer to Utilities – Regulatory Developments - ATCO Gas - Carbon Natural Gas Storage Facility section).

Temperatures

ATCO Gas, pursuant to the AUC decision on its 2008-2009 general rate application issued on November 13, 2008, has received approval to establish deferral accounts deferring the impact of temperature fluctuations on ATCO Gas' revenues commencing January 1, 2008. The deferral account mechanism largely eliminates the impact of temperature on ATCO Gas' earnings.

Benchmarking

ATCO Electric, ATCO Gas, and ATCO Pipelines (the ATCO Utilities) purchase information technology services from ATCO I-Tek. ATCO Electric and ATCO Gas also purchase customer care and billing services from ATCO I-Tek. The recovery of these costs in customer rates is subject to AUC approval. Since 2003, the costs have been approved on a placeholder basis, and are subject to final AUC approval after completion of a collaborative benchmarking process.

The benchmarking report, dealing with the period of 2003-2007, was received on January 23, 2008. In February 2008, the benchmarking report along with an application to adjust the placeholder rates was filed with the AUC. In April 2008, an agreement with the customer group concerning the adjustment to placeholders was submitted to the AUC for approval. Should this agreement be approved by the AUC, it is not expected to have a material impact on consolidated earnings. The AUC has established a further process for the 2003 – 2007 period with a hearing scheduled for the second quarter of 2009 to review the issues related to the application and subsequent agreement with the customer group.

For the 2008 and 2009 period, a separate regulatory process will occur to approve rates for information technology and customer care and billing services provided by ATCO I-Tek that can be included in customer rates. The 2008-2009 proceeding will commence after the completion of the 2003-2007 process.

In 2009, the ATCO Utilities will continue to utilize placeholder rates for information technology and customer care and billing services until final rates are determined by the AUC.

A further regulatory process to deal with rates for information technology and customer care and billing services provided by ATCO I-Tek for 2010 and beyond has been established and the AUC is expected to set a schedule for this regulatory process in the second quarter of 2009.

Transfer of the Retail Energy Supply Businesses

On May 4, 2004, ATCO Gas and ATCO Electric transferred their retail energy supply businesses to Direct Energy and one of its affiliates (collectively Direct Energy), a subsidiary of Centrica plc. ATCO Gas and ATCO Electric continue to own and operate the natural gas and electricity distribution systems used to deliver energy.

Although ATCO Gas and ATCO Electric transferred to Direct Energy certain retail functions, including the supply of natural gas and electricity to customers and billing and customer care functions, the legal obligations of ATCO Gas and ATCO Electric remain if Direct Energy fails to perform. In certain events (including where Direct Energy fails to supply natural gas and/or electricity and ATCO Gas and/or ATCO Electric are ordered by the AUC to do so), the functions will revert to ATCO Gas and/or ATCO Electric with no refund of the transfer proceeds to Direct Energy by ATCO Gas and/or ATCO Electric.

Centrica plc, Direct Energy's parent, has provided a $300 million guarantee, supported by a $235 million letter of credit in respect of Direct Energy's obligations to ATCO Gas, ATCO Electric and ATCO I-Tek in respect of the ongoing relationships contemplated under the transaction agreements. However, there can be no assurance that the coverage under these agreements will be adequate to cover all of the costs that could arise in the event of a reversion of such functions.

Canadian Utilities has provided a guarantee of ATCO Gas', ATCO Electric's and ATCO I-Tek's payment and indemnity obligations to Direct Energy contemplated under the transaction agreements.

Late Payment Penalties on Utility Bills

As a result of decisions of the Supreme Court of Canada in Garland vs. Consumers' Gas Co., the imposition of late payment penalties on utility bills has been called into question. ATCO is unable to determine at this time the impact, if any, that these decisions will have on the Company.

Measurement Inaccuracies in Metering Facilities

Measurement inaccuracies occur from time to time with respect to ATCO Electric's, ATCO Gas' and ATCO Pipelines' metering facilities. Measurement adjustments are settled between parties based on the requirements of the Electricity and Gas Inspections Act (Canada) and applicable regulations issued pursuant thereto. There is a risk of disallowance of the recovery of a measurement adjustment if controls and timely follow up are found to be inadequate by the AUC.

Alberta Power (2000)

Alberta Power (2000) has two regulated operations, the Battle River and Sheerness generating plants, which were regulated by the AUC until December 31, 2000, but are now governed by legislatively mandated PPAs that were approved by the AUC. These plants are included in regulated operations primarily because the PPAs are designed to allow the owners of generating plants constructed before January 1, 1996, to recover their forecast fixed and variable costs and to earn a return at the rate specified in the PPAs. The plants will become deregulated upon the earlier of one year after the expiry of a PPA or

a decision to continue to operate the plant. For PPAs expiring prior to 2019, Alberta Power (2000) has one year after the expiry of a PPA to determine whether to decommission the generating plant in order to fully recover plant decommissioning costs or to continue to operate the plant. For PPAs expiring after 2018 decommissioning costs are the responsibility of the plant owner. Each PPA is to remain in effect until the earlier of the last day of the estimated life of the related generating plant or December 31, 2020.

Over 99% of the electricity generated by Alberta Power (2000) is sold pursuant to PPAs. Under the PPAs, Alberta Power (2000) is required to make the generating capacity for each generating unit available to the purchaser of the PPA for that unit. In return, Alberta Power (2000) is entitled to recover its forecast fixed and variable costs for that unit from the PPA purchaser, including a return on common equity equal to the long term Government of Canada bond rate plus 4.5% based on a deemed common equity ratio of 45%. Many of the forecast costs will be determined by indices, formulae or other means for the entire period of the PPA. Alberta Power (2000)'s actual results will vary and depend on performance compared to the forecasts on which the PPAs were based.

Fuel costs in Alberta Power (2000) are mostly for coal supply. To protect against volatility in coal prices, Alberta Power (2000) owns or has sufficient coal supplies under long term contracts for the anticipated lives of its Battle River and Sheerness coal-fired generating plants. These contracts are at prices that are either fixed or indexed to inflation.

NON-REGULATED OPERATIONS

ATCO Power

The Company's portfolio of non-regulated electric generating plants is made up of gas-fired cogeneration, gas-fired combined cycle, gas-fired simple cycle, and small hydro plants. The majority of operating income from power generation operations is derived through long term power, steam and transmission support agreements. Where long term agreements are in place, the purchaser assumes the fuel supply and price risks and the Company, under these agreements, assumes the operating risks.

ATCO Power's generating plants include high efficiency gas-fired cogeneration plants, with associated on-site steam and power tolling arrangements, and gas-fired peaking and hydroelectric plants with underlying transmission support agreements. In 2008, sales from approximately 70% of ATCO Power's generating capacity were subject to long term agreements, while the remaining 30% consisted primarily of sales to the Alberta Power Pool and the U.K. merchant power market. In 2009, these percentages are expected to be approximately the same. These sales are dependent on prices in the Alberta electricity spot market and in the U.K. merchant power market. The majority of the electricity sales to the Alberta Power Pool are from gas-fired generating plants, and as a result operating income is affected by natural gas prices. During peak electricity usage hours in Alberta, a good correlation exists between electricity spot prices and natural gas spot prices. During off-peak hours, there is less correlation. The correlation is expected to increase in the future as customer load grows and older plants are decommissioned.

Changes and volatility in Alberta Power Pool electricity prices, natural gas prices and related spark spreads may have a significant impact on the Company's earnings and cash flow from operations in the future. The Company has adopted asset optimization strategies for bidding its merchant power into the Alberta and U.K. power markets.

Since October 2004, 27.5% of the power generated at ATCO Power's Barking generating plant has been sold into the U.K. power exchange market. A substantial proportion of the UK electricity market is comprised of vertically integrated companies whose operations include both generation and supply. Market participants trade primarily through structured bilateral contracts and wholesale markets, with smaller volumes traded on a power exchange. Approximately 40% of the electricity generated is supplied

from natural gas-fired generating plants. The Barking generating plant has a fixed price gas purchase agreement which expires in September 2010 and, as a result, has been able to experience strong margins due to the high market prices for electricity. Changes in the U.K. market electricity prices may have an impact on the Company's earnings and cash flow from operations in the future.

ATCO Power has financed the majority of its non-regulated electrical generating capacity on a non-recourse basis. In these projects, the lender's recourse in the event of default is limited to the business and assets of the project in question, which includes the Company's equity therein. Canadian Utilities has provided a number of guarantees related to ATCO Power's and ATCO Resources' obligations under their respective non-recourse loans associated with certain of their projects. ATCO Power (80%) and ATCO Resources (20%) have a joint venture in these projects subject to guarantees, excluding Barking Power. ATCO Ltd. has indemnified and agreed to reimburse Canadian Utilities for any amounts it may be required to pay under these guarantees in respect of ATCO Resources' 20% interest. The guarantees outstanding at December 31, 2008, are described in Note 11 to the consolidated financial statements. To date, Canadian Utilities has not been required to make any payments related to its guaranteed obligations.

The Company's generating plants are exposed to operational risks which may cause outages due to such issues as boiler, turbine, and generator failures. In order to mitigate this risk, a proactive maintenance program is carried out on a regular basis with scheduled outages for major overhauls and other maintenance issues. In addition, the Company carries property and business interruption insurance to protect against the risk of extended outages.

ATCO Midstream

ATCO Midstream is exposed to the difference between the selling prices of the NGL produced and the purchase price of shrinkage gas. The amount of profit made from ATCO Midstream's NGL extraction operations will increase or decrease as the difference between the price of NGL and natural gas commodities increases or decreases.

ATCO Midstream is exposed to seasonal natural gas price spreads. The amount of earnings and cash flow from the storage business will vary as the differences between the price of natural gas in the summer and the following winter fluctuates. To mitigate this risk ATCO Midstream maintains portfolios of varied contracts, delivery terms, capacities and customers for its storage operations.

In June 2007, the AUC initiated an industry wide review of NGL extraction rights in anticipation of the existing industry agreement expiring in 2008. On February 4, 2009, the AUC issued a decision with respect to NOVA's natural gas transmission system that, in most situations, transfers ownership of the NGL extraction rights to the producer from the NOVA delivery service customer. The implementation of this decision is expected to occur in three years time. The earnings and cash flow impact on certain of ATCO Midstream's NGL extraction facilities is uncertain at this time.

ATCO Frontec

ATCO Frontec's operations include providing support to military agencies in foreign locations which may be subject to war risk. ATCO Frontec maintains insurance, including war risks, to mitigate the risk associated with the nature of these contracts. Additionally, in areas where the risk of injury is considered to be severe, ATCO Frontec confines its staff to specific military compounds and all employees are given pre-deployment orientation and ongoing safety training.

A fuel spill occurred in January 2007 at the Brevoort Island, Northwest Territories, radar site maintained by Nasittuq Corporation, a corporation jointly owned by ATCO Frontec and Pan Arctic Inuit Logistics Corporation. ATCO has sufficient insurance coverage in place to cover any material amounts that might

become payable as a result of the fuel spill. Accordingly, this spill is not expected to have any material impact on the Company's financial position.

ATCO I-Tek

ATCO Electric, ATCO Gas, and ATCO Pipelines purchase information technology services from ATCO I-Tek. ATCO Electric and ATCO Gas also purchase customer care and billing services from ATCO I-Tek. The recovery of these costs in customer rates is subject to AUC approval. Since 2003, the costs have been approved on a placeholder basis, and are subject to final AUC approval after completion of a collaborative benchmarking process. A benchmarking report was received on January 23, 2008.

Adjustments to ATCO I-Tek's fees as a result of the benchmarking report for information technology services will be retroactive to January 1, 2008. Price changes relating to ATCO I-Tek's customer care and billing contract services for ATCO Gas and ATCO Electric will be applied following renegotiation of a new fee schedule. The benchmarking report has resulted in reduced revenues for ATCO I-Tek in 2008 and will result in reduced revenues in 2009 and beyond for services provided to ATCO Electric, ATCO Gas, and ATCO Pipelines.

Derivative Financial Instruments

In conducting its business, the Company uses various instruments, including forward contracts, swaps and options, to manage the risks arising from fluctuations in exchange rates, interest rates and commodity prices. All such instruments are used only to manage risk and not for trading purposes. For details on the financial instruments in place at December 31, 2008, see Note 21 to the consolidated financial statements.

The Canadian Institute of Chartered Accountants (CICA) recommendations require the recognition and measurement of derivative instruments embedded in host contracts that were issued, acquired or substantively modified on or after January 1, 2003. Derivative instruments embedded in host contracts that were issued, acquired or substantively modified prior to January 1, 2003, have not been identified and recognized in the consolidated financial statements as permitted by the recommendations.

The Company designates each derivative instrument as either a hedging instrument or a non-hedge derivative:

(a) A hedging instrument is designated as either:
   (i) a fair value hedge of a recognized asset or liability or,
   (ii) a cash flow hedge of either:
      - a specific firm commitment or anticipated transaction or,
      - the variable future cash flows arising from a recognized asset or liability.

   At inception of a hedge, the Company documents the relationship between the hedging instrument and the hedged item, including the method of assessing retrospective and prospective hedge effectiveness. At the end of each period, the Company assesses whether the hedging instrument has been highly effective in offsetting changes in fair values or cash flows of the hedged item and measures the amount of any hedge ineffectiveness. The Company also assesses whether the hedging instrument is expected to be highly effective in the future.

   A hedging instrument is recorded on the consolidated balance sheet at fair value. Payments or receipts on a hedging instrument that is determined to be highly effective as a hedge are recognized concurrently with, and in the same financial category as, the hedged item. Subsequent changes in the fair value of a fair value hedge are recognized in earnings concurrently with the hedged item. For a cash flow hedge, the effective portion of changes in fair value is recognized in other comprehensive

income and is subsequently transferred to earnings concurrently with the hedged item, whereas the portion of the changes in fair value that is not effective at offsetting the hedged exposure is recognized in earnings.

If a hedging instrument ceases to be highly effective as a hedge, is de-designated as a hedging instrument or is settled prior to maturity, then the Company ceases hedge accounting prospectively for that instrument; for a cash flow hedge, the gain or loss deferred to that date remains in accumulated other comprehensive income and is transferred to earnings concurrently with the hedged item. Subsequent changes in the fair value of that derivative instrument are recognized in earnings.

If the hedged item is sold, extinguished or matures prior to the termination of the related hedging instrument, or if it is probable that an anticipated transaction will not occur in the originally specified time frame, then the gain or loss deferred to that date for the related hedging instrument is immediately transferred from accumulated other comprehensive income to earnings.

Hedge gains or losses that were recognized in other comprehensive income are added to the initial carrying amount of a non-financial asset or non-financial liability when:
(i) an anticipated transaction for a non-financial asset or non-financial liability becomes a specific firm commitment for which fair value hedge accounting is applied or,
(ii) a cash flow hedge of an anticipated transaction subsequently results in the recognition of the non-financial asset or non-financial liability.

(b) A non-hedge derivative instrument is recorded on the consolidated balance sheet at fair value and subsequent changes in fair value are recorded in earnings.

The Company applies settlement date accounting to the purchases and sales of financial assets. Settlement date accounting implies the recognition of an asset on the day it is received by the Company and the recognition of the disposal of an asset on the day that it is delivered by the Company. Any gain or loss on disposal is also recognized on that day.

Transaction costs that are directly attributable to the acquisition or issue of financial assets or financial liabilities that are not held for trading are added to the fair value of such assets or liabilities at time of initial recognition.

Transactions with Related Parties

In transactions with ATCO Ltd. and its wholly owned subsidiary corporations, the Company sold fuel in the amount of $2.6 million (2007 — $2.0 million), provided computer operations and systems development services totaling $14.1 million (2007 – $6.7 million), recovered administrative expenses totaling $1.5 million (2007 — $1.6 million) and incurred administrative expenses and corporate signature rights totaling $8.9 million (2007 — $8.3 million). The Company also incurred capital expenditures of $10.3 million (2007 — $9.4 million) that were recorded in property, plant and equipment.

In transactions with entities related through common control, the Company provided security services and recovered administrative expenses totaling nil (2007 – $0.3 million) and incurred advertising, promotion and administrative expenses totaling $1.4 million (2007 — $1.5 million).

At December 31, 2008, accounts receivable due from related parties amounted to $3.3 million (2007 – $0.8 million) and accounts payable due to related parties amounted to $6.6 million (2007 – $8.3 million).

The Company's transactions with related parties are in the normal course of business and under normal commercial terms, and did not have a material impact on earnings.

Off-Balance Sheet Arrangements

At December 31, 2008, unrecorded future income tax liabilities of the regulated operations amounted to $192.2 million. The liabilities include $1.6 million in respect of Alberta Power (2000)'s generating plants, which will be recovered through future payments received in respect of the PPA's. There are tax loss carryforwards of $0.3 million for Canadian subsidiary corporations for which no benefit has been recorded. The losses for the Canadian subsidiary corporations begin to expire in 2015. For additional information on the Company's unrecorded future income tax liabilities, refer to Note 6 to the consolidated financial statements.

Other than the financial instruments discussed under the Derivative Financial Instruments section, the Company does not have any off-balance sheet arrangements that have, or are reasonably likely to have, a current or future effect on the results of operations or financial condition, including, without limitation, such considerations as liquidity and capital resources.

Contingencies

The Company is party to a number of disputes and lawsuits in the normal course of business. The Company believes that the ultimate liability arising from these matters will have no material impact on the consolidated financial statements.

Critical Accounting Estimates

The preparation of the Company's consolidated financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the year. On an on-going basis, management reviews its estimates, particularly those related to depreciation and amortization methods, useful lives and impairment of long-lived assets, amortization of deferred availability incentives, asset retirement obligations, employee future benefits and the fair values of financial instruments, using currently available information. Changes in facts and circumstances may result in revised estimates, and actual results could differ from those estimates. The Company's critical accounting estimates are discussed below.

DEFERRED AVAILABILITY INCENTIVES

Alberta Power (2000) is subject to an incentive/penalty regime related to generating unit availability. The amount to be amortized is dependent upon estimates of future generating unit availability and future electricity prices over the term of the PPAs. Each quarter, management uses these estimates to forecast high case, low case and most likely scenarios for the incentives to be received from, less penalties to be paid to, the PPA counterparties. These forecasts are added to the accumulated unamortized deferred availability incentives outstanding at the end of the quarter; the resulting total is divided by the remaining term of the PPAs to arrive at the amortization for the quarter. As at December 31, 2008, the Company had recorded $61.3 million of deferred availability incentives. The amortization of deferred availability incentives recorded in revenues amounted to $12.6 million in 2008.

Compared to the most likely scenario recorded in revenues for the year, the high case scenario would have resulted in higher revenues of approximately \$5.2 million, whereas the low case scenario would have resulted in lower revenues of approximately \$5.9 million.

EMPLOYEE FUTURE BENEFITS

The expected long term rate of return on pension plan assets is determined at the beginning of the year on the basis of the long bond yield rate plus an equity and management premium that reflects the plan asset mix. Actual balanced fund performance over a longer period suggests that this premium is about 1.5%, which, when added to the long bond yield rate of 5.5% at the beginning of 2008, resulted in an expected long term rate of return of 7.0% for 2008. This methodology is supported by actuarial guidance on long term asset return assumptions for the Company's defined benefit pension plans, taking into account asset class returns, normal equity risk premiums, and asset diversification effect on portfolio returns.

Expected return on plan assets for the year is calculated by applying the expected long term rate of return to the market related value of plan assets, which is the average of the market value of plan assets at the end of the preceding three years. The expected long term rate of return has declined over the past seven years, from 8.1% in 2001 to 7.0% in the year ended December 31, 2008. The result has been a decrease in the expected return on plan assets and a corresponding increase in the cost of pension benefits. In addition, the actual return on plan assets over the same period has been lower than expected (i.e., an experience loss), which is also contributing to an increase in the cost of pension benefits as losses are amortized to earnings.

Accrued benefit obligations at the end of the year are determined using a discount rate that reflects market interest rates that match the timing and amount of expected benefit payments. Due to the recent, unprecedented events in the financial markets associated with the current credit environment which has resulted in significantly higher yields than normal, the current discount rate selection methodology has been refined to include high quality corporate bonds and quasi-government organizations. The liability discount rate has also declined over the same period, from 6.9% at the end of 2001 to 5.5% at the end of 2007, but has since increased to 7.0% for 2008. The result has been a decrease in benefit obligations (i.e., an experience gain), which is contributing to a decrease in the cost of pension benefits as gains are amortized to earnings.

In accordance with the Company's accounting policy to amortize cumulative experience gains and losses in excess of 10% of the greater of the accrued benefit obligations or the market value of plan assets, the Company began amortizing a portion of the net cumulative experience losses on plan assets and accrued benefit obligations in 2003 for both pension benefit plans and other post employment benefit plans and continued this amortization in 2008.

The assumed annual health care cost trend rate increases used in measuring the accumulated post employment benefit obligations in the year ended December 31, 2008, are as follows: for drug costs, 7.2% starting in 2008 grading down over five years to 4.5%, and for other medical and dental costs, 4.0% for 2008 and thereafter. Combined with lower recent claims experience, the effect of these changes has been to decrease the costs of other post employment benefits.

The effect of changes in these estimates and assumptions is mitigated by an AUC decision to record the costs of employee future benefits when paid rather than accrued. Therefore, a significant portion of the benefit plans expense or income is unrecognized by the regulated operations, excluding Alberta Power (2000).

The sensitivities of key assumptions used in measuring accrued benefit obligations and benefit plan cost (income) for 2008 are outlined in the following table. The sensitivities of each key assumption have been

calculated independently of changes in other key assumptions. Actual experience may result in changes in a number of assumptions simultaneously.

($ millions)	2008 Pension Benefit Plans		2008 Other Post Employment Benefit Plans	
	Accrued Benefit Obligation	Benefit Plan Cost	Accrued Benefit Obligation	Benefit Plan Cost
Expected long term rate of return on plan assets				
1% increase [1]	-	(4.3)	-	-
1% decrease [1]	-	4.3	-	-
Liability discount rate				
1% increase [1]	(80.9)	(4.6)	(3.2)	(0.2)
1% decrease [1]	102.0	8.0	4.0	0.2
Future compensation rate				
1% increase [1]	20.1	2.7	-	-
1% decrease [1]	(18.5)	(2.5)	-	-
Long term inflation rate				
1% increase [1] [2] [3]	36.8	4.5	3.0	0.2
1% decrease [1] [3]	(64.4)	(6.8)	(2.5)	(0.2)

Notes:

(1) Sensitivities are net of the associated regulatory asset (liability) and unrecognized defined benefit plans cost, which reflect an AUC decision to record costs of employee future benefits in the regulated operations, excluding Alberta Power (2000), when paid rather than accrued.

(2) The long term inflation rate for pension plans reflects the fact that pension plan benefit payments are indexed to increases in the Canadian Consumer Price Index to a maximum increase of 3.0% per annum.

(3) The long term inflation rate for other post employment benefit plans is the assumed annual health care cost trend rate described in the weighted average assumptions.

Changes in Accounting Policies

Effective January 1, 2008, the Company adopted the Canadian Institute of Chartered Accountants (CICA) recommendations for capital disclosures which require disclosure of qualitative and quantitative information regarding the Company's objectives, policies and processes for managing capital (refer to Note 15 to the consolidated financial statements). The recommendation requires additional disclosure in the notes to the financial statements.

Effective January 1, 2008, the Company adopted the CICA recommendations pertaining to disclosure and presentation of financial instruments which require disclosure of the classification of the Company's financial instruments and additional qualitative and quantitative information regarding the nature and extent of risks arising from financial instruments to which the Company is exposed (refer to Note 21 to the consolidated financial statements). The recommendation requires additional disclosure in the notes to the financial statements.

Effective January 1, 2008, the Company adopted the CICA recommendations for measurement and disclosure of inventories which provide guidance on the determination of cost and its subsequent

recognition as an expense, including any write-down to net realizable value, and on the cost formulas that are used to assign costs to inventories. The recommendations also clarified that major spare parts are to be included in property, plant and equipment. As a result of adopting these recommendations, the Company reclassified $1.8 million of inventories to property, plant, and equipment related to major spare parts on January 1, 2008 (refer to Note 1 to the consolidated financial statements).

FUTURE ACCOUNTING CHANGES

Effective for the Company beginning January 1, 2009, the CICA has removed a temporary exemption in its accounting recommendations that permitted assets and liabilities arising from rate regulation to be recognized and measured on a basis other than in accordance with the primary sources of GAAP. As permitted by Canadian GAAP, the Company will use standards issued by the Financial Accounting Standards Board in the United States that allow for the recognition and measurement of rate regulated assets and liabilities as another source of Canadian GAAP. The adoption of these standards is not expected to have a material impact on the earnings of the Company. However, it is anticipated that the reserves for future removal and site restoration costs, which are currently netted against property, plant and equipment, will be reclassified to non-current liabilities, resulting in an increase to the Company's total assets and liabilities. The amount of such future removal and site restoration costs at December 31, 2008, was $461.2 million. The CICA has also issued new recommendations that will require the recognition of future income tax assets and liabilities as well as a separate regulatory asset or liability for the amount of future income taxes expected to be included in future rates and recovered from or paid to future customers. The amount of unrecorded future income tax liabilities of the regulated operations at December 31, 2008 was $192.2 million. Upon adoption of the new standard, the Company expects to record an increase in future income tax liabilities and non-current regulatory assets of approximately $255 million. The additional amount reflects the future income tax effects of the settlement mechanism of the regulatory assets through customer rates that would occur in the future periods. These recommendations will be applied prospectively.

The CICA has issued new accounting recommendations for goodwill and intangible assets which establish standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets (including internally developed intangible assets). These recommendations are effective for the Company beginning January 1, 2009. Goodwill and intangible assets that are not assets as defined by GAAP will be derecognized and charged to the equity of the Company at that date. The adoption of these recommendations is not expected to have a material impact on the earnings or assets of the Company.

International Financial Reporting Standards

The Canadian Accounting Standards Board confirmed in 2008 that the use of International Financial Reporting Standards ("IFRS") by publicly accountable enterprises will be required in 2011. The Company will need to begin reporting under IFRS in the first quarter of 2011 with comparative data for the prior year. IFRS uses a conceptual framework similar to Canadian GAAP, but there could be significant differences in recognition, measurement and disclosures that will need to be addressed.

The Company has established a Steering Committee, a project team, and working groups to review the adoption of IFRS. The project team and working groups provide position papers and regular updates to management, the Steering Committee and the Audit Committee. Education sessions have been, and will continue to be, provided for employees, senior management and the Audit Committee to increase knowledge and awareness of IFRS and its impacts. An external expert advisor has been engaged. The Company is participating in various industry groups, including the Canadian Energy Pipeline Association, the Canadian Gas Association and the Canadian Electric Association.

The Company's IFRS Conversion Project consists of three phases: Assessment and Diagnostic; Design and Planning; and Implementation and Review. Position papers are being prepared on issue-specific accounting differences between Canadian GAAP and IFRS and the impact on financial reporting computer systems. These position papers are being reviewed with the Company's auditors. As a number of the IFRS standards are changing, the position papers will be updated to reflect any changes resulting from the final standards. The Company is also evaluating the potential impact of IFRS on financial covenants, business contracts and internal controls over financial reporting.

The Company reviews discussion papers, exposure drafts and standards released by the International Accounting Standards Board and the International Financial Reporting Interpretations Committee. The Company will continue to assess the impact of the proposed standards on its financial statements and disclosure as additional information becomes available. Financial impacts cannot be reasonably determined at this time.

Based on initial assessments the Company has identified that the following areas have the greatest potential impact to the Company's accounting: property, plant and equipment, joint arrangements, leases, rate regulated operations, deferred availability incentives and employee benefits. There will also be a significant amount of effort to comply with the IFRS' requirements for initial adoption of IFRS.

A more detailed analysis and evaluation of the financial impact of the issues identified in the assessment and diagnostic phases and the impact on and implementation of financial reporting computer systems will be completed in 2009.

Quarterly Results of Operations

SELECTED INFORMATION

	For the Three Months Ended (1) (2) (3)				
($ millions except per share data)	**Mar. 31**	**Jun. 30**	**Sep. 30**	**Dec. 31**	**Total**
			(unaudited)		
2008					
Revenues	740.6	655.6	638.4	744.3	2,778.9
Earnings attributable to Class A and Class B Shares	150.0	82.2	66.7	114.2	413.1
Earnings per Class A and Class B Share	1.20	0.65	0.53	0.91	3.29
Diluted earnings per Class A and Class B Share	1.19	0.65	0.53	0.91	3.28
Adjusted Earnings (4)	149.7	70.3	71.3	110.5	401.8
Adjusted Earnings per Class A and Class B Share (4)	1.19	0.56	0.57	0.88	3.20
2007					
Revenues	697.6	560.3	489.9	657.1	2,404.9
Earnings attributable to Class A and Class B Shares	134.7	81.1	72.2	98.7	386.7
Earnings per Class A and Class B Share	1.07	0.65	0.58	0.78	3.08
Diluted earnings per Class A and Class B Share	1.07	0.64	0.58	0.78	3.07
Adjusted Earnings (4)	130.2	67.5	70.6	75.5	343.8
Adjusted Earnings per Class A and Class B Share (4)	1.04	0.54	0.56	0.60	2.74

Notes:

(1) *There were no discontinued operations or extraordinary items during these periods.*

(2) *Due to certain factors, revenues for any quarter are not necessarily indicative of operations on an annual basis. These factors include the seasonal nature of the Company's operations, changes in electricity prices in Alberta, the timing and demand of natural gas storage capacity sold, changes in natural gas storage fees, changes in NGL prices and natural gas costs and the timing of rate decisions.*

(3) *The above data (other than Adjusted Earnings and Adjusted Earnings per Class A and Class B Share) has been extracted from the financial statements, which have been prepared in accordance with GAAP, and the reporting currency is the Canadian dollar.*

(4) *Refer to Significant Non-Operating Financial Items section for a description of the adjustments made to earnings attributable to Class A and Class B Shares to obtain Adjusted Earnings.*

The principal factors that caused variations in financial condition and results of operations over the past eight quarters were:

- unplanned and planned outages affecting availability in ATCO Power's and Alberta Power (2000)'s generating plants;
- the timing of utility rate decisions;
- amount of franchise fees collected by ATCO Gas on behalf of cities and municipalities;
- fluctuations in temperatures, natural gas prices, electricity prices and related spark spreads in Alberta and the U.K.;
- changes in market conditions in ATCO Midstream's NGL and storage operations;
- changes in business activity in ATCO Frontec;
- exchange rates;
- changes in the quarterly depreciation expense allocation in ATCO Gas;
- mark to market adjustments in ATCO Power;
- Other Post Employment Benefits;
- Federal Court of Appeal Decision - Mining Assets;
- 2008 Tax Assessment;
- 2007 Changes in Income Taxes and Rates;
- 2007 Changes in the Taxation of Preferred Share Dividends;
- ATCO Gas Tax Reassessments; and
- changes in share appreciation rights expense due to changes in ATCO Class I non-voting share and Canadian Utilities' Class A non-voting share prices.

Fourth Quarter 2008

All quarterly information in this document is unaudited and has been shaded to differentiate it from the annual information.

SEGMENTED REVENUE

($ millions)	For the Three Months Ended December 31		
	2008	2007	Change to 2008 (2008-2007)
		(unaudited)	
Utilities	**331.3**	313.3	6%
Power Generation	**249.1**	193.9	28%
Global Enterprises	**209.0**	198.2	5%
Corporate and Other	**3.6**	3.5	3%
Intersegment eliminations	**(48.7)**	(51.8)	6%
Revenues	**744.3**	657.1	13%

Notes:

(1) *There were no discontinued operations or extraordinary items during these periods.*

(2) *Due to certain factors, revenues for any quarter are not necessarily indicative of operations on an annual basis. These factors include the seasonal nature of the Company's operations, changes in electricity prices in Alberta, the timing and demand of natural gas storage capacity sold, changes in natural gas storage fees, changes in NGL prices and natural gas costs and the timing of rate decisions.*

(3) *The above data has been extracted from the financial statements, which have been prepared in accordance with GAAP and the reporting currency is the Canadian dollar.*

Fourth quarter **revenues increased** by $87.2 million primarily due to higher natural gas fuel purchases recovered on a "no-margin" basis, improved merchant operations and increased availability in ATCO Power's U.K. operations and improved merchant performance in ATCO Power's Alberta generating plants. In addition, increased business activity in ATCO Frontec's operations and the ATCO Gas GRA contributed to the increase in revenues. These increases were partially offset by lower prices for NGL extraction in ATCO Midstream.

Temperatures in ATCO Gas for the three months ended December 31, 2008, were 0.8% colder than normal, compared to 0.8% colder than normal in 2007. ATCO Gas, pursuant to the AUC decision on its 2008-2009 general rate application issued on November 13, 2008, has received approval to establish deferral accounts deferring the impact of temperature fluctuations on ATCO Gas' revenues commencing January 1, 2008. The deferral account mechanism largely eliminates the impact of temperature on ATCO Gas' earnings.

SEGMENTED EARNINGS ATTRIBUTABLE TO CLASS A AND CLASS B SHARES

($ millions)	For the Three Months Ended December 31 [1] [2] [3]		
	2008	2007	Change to 2008 (2008-2007)
		(unaudited)	
Utilities	**45.8**	48.0	(5%)
Power Generation	**46.0**	25.5	80%
Global Enterprises	**31.9**	27.7	15%
Corporate and Other	**(9.3)**	(4.1)	127%
Intersegment eliminations	**(0.2)**	1.6	113%
Earnings attributable to Class A and Class B Shares	**114.2**	98.7	16%
Earnings per Class A and Class B Share	**0.91**	0.78	17%
Diluted earnings per Class A and Class B Share	**0.91**	0.78	17%
Adjusted earnings per Class A and Class B Share	**0.88**	0.60	46%

Notes:

(1) *There were no discontinued operations or extraordinary items during these periods.*

(2) *Due to certain factors, earnings and Adjusted Earnings for any quarter are not necessarily indicative of operations on an annual basis. These factors include the seasonal nature of the Company's operations, changes in electricity prices in Alberta, the timing and demand of natural gas storage capacity sold, changes in natural gas storage fees, changes in NGL prices and natural gas costs and the timing of rate decisions.*

(3) *The above data (other than Adjusted Earnings and Adjusted Earnings per Class A and Class B Share) has been extracted from the financial statements, which have been prepared in accordance with GAAP and the reporting currency is the Canadian dollar.*

RECONCILIATION OF EARNINGS ATTRIBUTABLE TO CLASS A AND CLASS B SHARES AND ADJUSTED EARNINGS

For the Three Months Ended December 31

($ millions)	Utilities	Power Generation	Global Enterprises	Corporate & Other	Intersegment Eliminations	Total
2008						
Earnings attributable to Class A and Class B Shares	**45.8**	**46.0**	**31.9**	**(9.3)**	**(0.2)**	**114.2**
Mark-to-Market Adjustment [1]	-	**1.1**	-	-	-	**1.1**
2008 Tax Assessment [1]	**(3.3)**	-	-	-	-	**(3.3)**
Other Post Employment Benefits [1]	-	**(1.5)**	-	-	-	**(1.5)**
Adjusted Earnings	**42.5**	**45.6**	**31.9**	**(9.3)**	**(0.2)**	**110.5**
2007						
Earnings attributable to Class A and Class B Shares	48.0	25.5	27.7	(4.1)	1.6	98.7
2007 Changes in Income Taxes and Rates [1]	(0.3)	(8.2)	-	-	(2.4)	(10.9)
Mark-to-Market Adjustment [1]	-	(2.8)	-	-	-	(2.8)
ATCO Gas Tax Reassessments [1]	(9.5)	-	-	-	-	(9.5)
Adjusted Earnings	38.2	14.5	27.7	(4.1)	(0.8)	75.5

Note:

(1) *Refer to Significant Non-Operating Financial Items section for a description of the adjustments made to earnings attributable to Class A and Class B Shares to obtain Adjusted Earnings.*

Fourth quarter **earnings increased** by $15.5 million (16%) over 2007, including the impact of adjustments identified in the Significant Non-Operating Financial Items section.

Fourth quarter **Adjusted Earnings increased** by $35.0 million (46%) over 2007 primarily due to improved merchant performance in ATCO Power's Alberta generating plants, improved merchant performance and increased availability in ATCO Power's U.K. operations, and increased earnings of $3.5 million due to the change in quarterly depreciation expense allocation in ATCO Gas (ATCO Gas Depreciation Expense Adjustment, refer to Other Expenses - Depreciation Expense Adjustment section). These increases were partially offset by reduced activity in NGL extraction operations in ATCO Midstream.

Alberta Power Pool electricity prices for the three months ended December 31, 2008, averaged $95.20 per MWh, compared to average prices of $61.77 per MWh for the corresponding period in 2007. Natural gas prices for the three months ended December 31, 2008, averaged $6.35 per GJ, compared to average prices of $5.83 per GJ for the corresponding period in 2007. The consequence of these changes in electricity and natural gas prices was an average spark spread of $47.59 per MWh for the three months ended December 31, 2008, compared to $18.02 per MWh for the corresponding period in 2007.

During the three months ended December 31, 2008, the **deferred availability incentive** account **increased** by $16.1 million to $61.3 million, mainly due to reduced outages in the quarter, compared to the corresponding period in 2007. During the three months ended December 31, 2008, the amortization of deferred availability incentives, recorded in revenues, increased by $0.6 million to $3.5 million, compared to the corresponding period in 2007.

Interest and other income for the fourth quarter **decreased** by $6.7 million to $14.6 million primarily as a result of the mark-to-market adjustment in ATCO Power and lower rates of interest earned on lower cash balances.

OTHER EXPENSES

($ millions)	For the Three Months Ended December 31 **2008**	2007 *(unaudited)*	Change to 2008 (2008-2007)
Operating expenses:			
Natural gas supply	**3.6**	24.8	(85%)
Purchased power	**14.9**	13.6	10%
Operation and maintenance	**300.4**	251.4	19%
Selling and administrative	**87.2**	77.1	13%
Franchise fees	**42.5**	37.4	14%
	448.6	404.3	11%
Depreciation and amortization expenses	**100.5**	99.0	2%
Interest	**60.3**	55.0	10%
Income taxes	**27.1**	13.1	107%
Dividends on equity preferred shares	**8.2**	8.3	(1%)

Fourth quarter **operating expenses increased** by $44.3 million (11%) over 2007. Natural gas supply expense decreased primarily as a result of lower business activity in NGL extraction operations in

ATCO Midstream. Operation and maintenance expenses were higher, primarily due to the Barking outage in ATCO Power, and increased business activity in ATCO Frontec. Selling and administrative expenses increased primarily as a result of the impact of inflation, increased employment costs associated with higher employment levels resulting from increased growth and higher project development costs in ATCO Power. Increased franchise fees due to higher natural gas prices, recovered on a flow through basis, were paid in ATCO Gas.

Fourth quarter **depreciation and amortization expenses increased** by $1.5 million, primarily as a result of increased capital additions in 2007 and 2008, mainly in the Utilities segment and in ATCO Frontec, partially offset by the ATCO Gas Depreciation Expense Adjustment.

Interest expense for the fourth quarter **increased** by $5.3 million (10%) over the same period in 2007, primarily due to increased amounts of debt outstanding (net of redemptions) resulting from new financings issued in 2007 and 2008 to fund capital expenditures in the Utilities segment, partially offset by the repayment of ATCO Power's non-recourse financings in 2007 and 2008.

Income taxes in the fourth quarter **increased** by $14.0 million (107%) over the same period in 2007, mainly due to an increase in earnings before taxes, the 2007 Changes in Income Taxes and Rates and the 2007 ATCO Gas Tax Reassessments. These increases were partially offset by the impact of the higher tax deductions in the Utilities Business Group due to the use of the flow-through tax methodology, lower corporate income tax rates in 2008 and favorable tax decisions received in the Utilities Business Group in the fourth quarter to treat certain previously reported capital outlays as current expenditures for tax purposes.

Depreciation Expense Adjustment

Effective January 1, 2008, ATCO Gas prospectively changed the allocation of annual depreciation and amortization expense on a quarterly basis. The method of quarterly allocation has been changed from an estimate based on the timing of revenues to the straight line basis. This resulted in a decrease to ATCO Gas' depreciation and amortization expense for the three months ended December 31, 2008, of $4.9 million, as compared to the methodology used for the depreciation and amortization expense recorded in the corresponding period of 2007. The annual depreciation and amortization expense continues to be on the straight line basis, and therefore this change does not affect the total depreciation and amortization expense recognized for the year. This resulted in an increase to the Company's earnings for the three months ended December 31, 2008, of $3.5 million as compared to the methodology used in the corresponding period of 2007.

LIQUIDITY AND CAPITAL RESOURCES

SUMMARY OF CASH FLOW

($ millions)	For the Three Months Ended December 31		
	2008	2007	Change to 2008 (2008-2007)
		(unaudited)	
Cash position, beginning of period	**946.1**	682.9	39%
Cash provided by (used in):			
Operating activities	**145.3**	127.1	14%
Investing activities	**(290.3)**	(201.9)	44%
Financing activities	**(71.3)**	141.8	(150%)
Foreign currency impact on cash balances	**(3.2)**	(2.7)	(19%)
Cash position, end of period	**726.6**	747.2	(3%)

OPERATING ACTIVITIES

Cash flow from operations for the fourth quarter **increased** by 14% primarily due to increases in funds generated by operations, partially offset by changes in non-cash working capital. **Funds generated by operations increased** by 25%, primarily due to higher cash earnings and increased deferred availability incentives in Alberta Power (2000).

INVESTING ACTIVITIES

Investing in the fourth quarter **increased** by 44% primarily as a result of higher capital expenditures, partially offset by increased non-current deferred electricity costs, changes in non-cash working capital and higher contributions by utility customers for extensions to plant. **Increases** in **capital expenditures** reflect increased investment in regulated electric and natural gas distribution and transmission projects and in the Karratha generating plant in ATCO Power.

FINANCING ACTIVITIES

In the fourth quarter, the Company had **net debt decreases** of $28.4 million. **Issuance** of debt included $4.0 million of long term debt. **Redemptions** were comprised of $3.8 million of long term debt and $28.6 million of non-recourse long term debt.

In the fourth quarter, the Company had **no issues or redemptions** of equity preferred shares.

In the fourth quarter, there were **no purchases** of Class A Shares under its normal course issuer bids, a decrease of $8.0 million from the corresponding period in 2007. In the fourth quarter, **issues** of Class A Shares due to stock option exercises were $0.1 million, a decrease of $0.2 million over the corresponding period in 2007. In the fourth quarter, **net issues** were $0.1 million, a decrease of $7.8 million from the corresponding period in 2007.

In the fourth quarter, total **dividends paid to Class A and Class B share owners increased** by 5% to $41.7 million over the same period in 2007. In the fourth quarter, the **quarterly dividend** payment on the Company's Class A and Class B Shares **increased** by $0.0175 to $0.3325 per share.

FOREIGN CURRENCY TRANSLATION

Changes in U.K. and Australian exchange rates used for balance sheet translations impacted the Company's cash position by $(3.2) million.

CANADIAN UTILITIES LIMITED

Consolidated Five-Year Financial Summary

(Millions of Canadian dollars, except as indicated)		2008	2007	2006	2005	2004 [1]
EARNINGS						
Revenues		**2,778.9**	2,404.9	2,430.4	2,515.8	3,011.4
Operating expenses		**1,635.5**	1,401.6	1,390.7	1,553.9	2,107.5
Depreciation and amortization		**389.1**	351.5	348.5	311.5	291.5
Interest		**233.5**	217.4	222.9	210.0	203.7
Interest and other income		**(59.1)**	(64.3)	(58.5)	(36.6)	(94.1)
Income taxes		**134.3**	77.7	167.1	175.6	158.0
Dividends on equity preferred shares		**32.5**	34.3	35.8	35.8	35.8
Earnings attributable to Class A and Class B shares		**413.1**	386.7	323.9	265.6	309.0
Adjusted earnings [2]		**401.8**	343.8	320.8	-	-
SEGMENTED EARNINGS						
Utilities		**149.0**	139.7	121.2	106.0	168.7
Power generation		**151.0**	134.7	119.2	105.2	82.0
Global enterprises		**126.9**	110.0	101.0	78.8	70.1
Corporate and other/eliminations		**(13.8)**	2.3	(17.5)	(24.4)	(11.8)
Earnings attributable to Class A and Class B shares		**413.1**	386.7	323.9	265.6	309.0
BALANCE SHEET						
Cash [3]		**726.6**	747.2	798.8	824.4	698.3
Property, plant and equipment		**6,208.5**	5,678.5	5,426.1	5,208.7	5,042.5
Total assets		**7,864.4**	7,305.2	6,993.5	6,817.8	6,617.5
Capitalization:						
Long term debt		**2,844.3**	2,603.2	2,411.5	2,231.0	2,171.0
Non-recourse long term debt		**412.4**	478.1	626.7	673.8	760.9
Equity preferred shares		**625.0**	625.0	636.5	636.5	636.5
Share owners' equity [4]		**2,751.7**	2,521.7	2,324.7	2,223.5	2,117.7
Total capitalization		**6,633.4**	6,228.0	5,999.4	5,764.8	5,686.1
CASH FLOWS						
Funds generated by operations [5]		**804.6**	725.9	657.5	659.3	538.3
Purchase of property, plant and equipment		**1,010.9**	700.8	567.7	526.7	535.5
Financing (excluding Class A and B dividends)		**178.8**	58.0	44.4	(2.2)	333.8
Class A and B dividends		**166.8**	156.8	176.7	139.6	134.4
CLASS A & B SHARES						
Shares outstanding at end of year [4] (thousands)		**125,510**	125,295	125,388	126,892	126,783
Return on equity [4] (%)		**15.7**	16.0	14.3	12.2	15.2
Earnings per share [4] ($)		**3.29**	3.08	2.57	2.09	2.44
Adjusted Earnings per share [2], [4] ($)		**3.20**	2.74	2.54	-	-
Dividends paid per share [4] [6] ($)		**1.33**	1.25	1.40	1.10	1.06
Equity per share [4] ($)		**21.92**	20.13	18.54	17.52	16.70
Stock market record - Class A non-voting shares ($)	High	**51.80**	55.00	48.94	46.20	32.00
	Low	**33.11**	41.83	35.15	29.55	25.71
	Close	**40.50**	46.40	47.73	43.98	30.16
Stock market record - Class B common shares ($)	High	**51.75**	54.00	48.85	45.82	31.95
	Low	**33.04**	42.00	35.72	29.63	25.70
	Close	**40.00**	46.00	47.66	43.85	31.95

(1) Includes the gain on the transfer of retail energy supply businesses that occurred on May 4, 2004. Revenues and natural gas supply and purchased power costs after May 4, 2004 were reduced accordingly for 2004 and thereafter.

(2) Adjusted earnings are defined as earnings attributable to Class A and Class B shares after adjustments for items that are not in the normal course of business nor a result of day to day operations. The majority of these adjustments in 2008 related to tax issues and an adjustment for other post employment benefits. This measure is not defined by Generally Accepted Accounting Principles and may not be comparable to similar measures used by other companies. Adjusted earnings have been calculated starting in 2006, as a result, adjusted earnings for 2004 and 2005 are not included.

(3) Cash is defined as cash and short-term investments less bank indebtedness.

(4) Includes Class A non-voting shares and Class B common shares.

(5) Funds generated by operations is defined as cash generated from operations before changes in non-cash working capital. This measure is not defined by Generally Accepted Accounting Principles and may not be comparable to similar measures used by other companies.

(6) Dividends paid per share include a Special Dividend of $0.25 paid to Class A and Class B share owners on September 1, 2006.

CANADIAN UTILITIES LIMITED

Consolidated Five-Year Operating Summary

(Millions of Canadian dollars, except as indicated)	**2008**	2007	2006	2005	2004
Utilities					
Natural gas distribution operations					
Purchase of property, plant and equipment	**249.7**	191.6	167.4	174.0	154.3
Pipelines (thousands of kilometres)	**37.2**	36.5	35.9	35.4	34.8
Maximum daily demand (terajoules)	**2,130**	1,819	1,861	1,919	2,049
Natural gas sold [1] (petajoules)	**-**	-	-	-	103
Natural gas distributed [1] (petajoules)	**238**	233	219	216	120
Total system throughput (petajoules)	**238**	233	219	216	223
Average annual use per residential customer (gigajoules)	**124**	127	126	131	134
Degree days - Edmonton [2]	**4,051**	3,992	3,819	3,641	3,985
- Calgary [3]	**4,171**	4,058	3,910	3,934	3,978
Customers at year-end (thousands)	**1,022.2**	1,001.8	969.9	939.6	914.3
Electric distribution and transmission operations					
Purchase of property, plant and equipment	**518.4**	311.8	238.1	212.2	223.4
Power lines (thousands of kilometres)	**71.5**	70.9	70.1	69.2	68.0
Electricity distributed (millions of kilowatt hours)	**10,594**	10,744	10,286	9,926	9,910
Average annual use per residential customer (kWh)	**7,666**	7,690	7,495	7,214	7,475
Customers at year-end (thousands)	**228.2**	223.0	216.3	210.9	206.2
Natural gas transmission operations					
Purchase of property, plant and equipment	**81.7**	87.1	97.7	84.3	47.9
Pipelines (thousands of kilometres)	**8.4**	8.4	8.4	8.3	8.3
Contract demand for pipelines system access (terajoules/day)	**5,034**	5,143	5,032	4,830	4,606
Power Generation					
Purchase of property, plant and equipment	**75.8**	49.2	48.1	41.2	77.0
Generating capacity operated (megawatts)	**4,885**	4,840	4,840	4,840	4,840
Generating capacity owned (megawatts)	**2,503**	2,467	2,474	2,474	2,474
Availability (%)	**93.5**	91.6	93.0	92.5	91.9
Global Enterprises					
Purchase of property, plant and equipment	**56.2**	62.7	14.2	11.9	14.5
Natural gas processed (Mmcf/day)	**435**	478	480	476	427
Natural gas gathering lines (kilometres)	**1,000**	1,000	1,000	1,000	1,000

(1) Effective May 2004, with the transfer of the retail energy supply businesses, ATCO Gas' existing sales service customers became transportation service customers.

(2) Degree days - Edmonton - are defined as the difference of the mean daily temperature from 14.5 degrees Celsius.

(3) Degree days - Calgary - are defined as the difference of the mean daily temperature from 15.5 degrees Celsius.

GENERAL INFORMATION

INCORPORATION

Canadian Utilities Limited was incorporated under the laws of Canada on May 18, 1927 and was continued under the Canada Business Corporations Act by Articles of Continuance on August 15, 1979.

ANNUAL MEETING

The Annual Meeting of Share Owners will be held at 10:00 a.m., Thursday, May 7, 2009 at The Fairmont Hotel Macdonald, 10065 – 100th Street, Edmonton, Alberta.

AUDITORS

PricewaterhouseCoopers LLP
Calgary, Alberta

COUNSEL

Bennett Jones LLP
Calgary, Alberta

TRANSFER AGENT AND REGISTRAR

Class A non-voting and
Class B common shares and
Second Preferred
(Series W and X) Shares
CIBC Mellon Trust Company
Calgary/Montreal/Toronto/Vancouver

TRUSTEE AND REGISTRAR

Debentures
CIBC Mellon Trust Company
Calgary/Montreal/Toronto/Vancouver

STOCK EXCHANGE LISTINGS

Class A non-voting Symbol CU
Class B common Symbol CU.X
Cumulative Redeemable Second
Preferred Shares
5.80% Series W Symbol CU.PR.A
6.00% Series X Symbol CU.PR.B
Listing: The Toronto Stock Exchange

ATCO GROUP ANNUAL REPORTS

Annual Reports to Share Owners and Financial Information (Consolidated Financial Statements & Management's Discussion and Analysis) for Canadian Utilities Limited and its parent company, ATCO Ltd., are available upon request from:

ATCO Ltd. & Canadian Utilities Limited
Corporate Office
1400, 909 – 11th Avenue SW
Calgary, Alberta T2R 1N6

Telephone: (403) 292-7500
Website: www.canadian-utilities.com
www.atco.com

SHARE OWNER INQUIRIES

Dividend information and other inquiries concerning shares should be directed to:

CIBC Mellon Trust Company
P.O. Box 7010
Adelaide Street Postal Station
Toronto, Ontario
Canada M5C 2W9

Telephone: 1-800-387-0825
Outside of North America: +1 (416) 643-5500
Fax: (416) 643-5501
Website: www.cibcmellon.com

Printed in Canada

Canadian Utilities Limited
1400, 909 – 11th Avenue SW, Calgary, Alberta T2R 1N6

Telephone: (403) 292-7500
Fax: (403) 292-7623

www.canadian-utilities.com

CANADIAN UTILITIES

CANADIAN UTILITIES IS A DIVERSIFIED, CANADIAN-BASED, INTERNATIONAL GROUP OF COMPANIES

BUSINESS CHALLENGES
for Investor-Owned Utilities

FINDING AND SUPPORTING GREAT PEOPLE

ENVIRONMENTAL STEWARDSHIP
Feature Included

CANADIAN UTILITIES LIMITED
An *ATCO* Company

CANADIAN UTILITIES LIMITED
ANNUAL REPORT 2008

Canadian Utilities Limited is a diversified, Canadian-based, international group of companies focused on profitable sustainable growth and achievement with $7.9 billion in assets and more than 6,800 people actively engaged in Power Generation, Utilities (natural gas and electricity transmission and distribution) and Global Enterprises (technology, logistics and energy services).

On the Cover

Brent Labrie, a journeyman lineman based out of ATCO Electric's Bonneyville District Office, is one of the more than 1,400 ATCO Electric employees Albertans count on for the safe, reliable delivery of electricity to homes, farms, and businesses. ATCO Electric serves almost two-thirds of Alberta.

Back Cover

Construction of ATCO Electric's new Brintnell-Wesley Creek transmission line, from the Wabasca area northeast of Lesser Slave Lake to the Peace River region, will strengthen the grid system in Alberta's northwest.

Opposite Page

ATCO Gas operators undertake work to safely maintain the Company's 37,000 kilometre natural gas distribution system.

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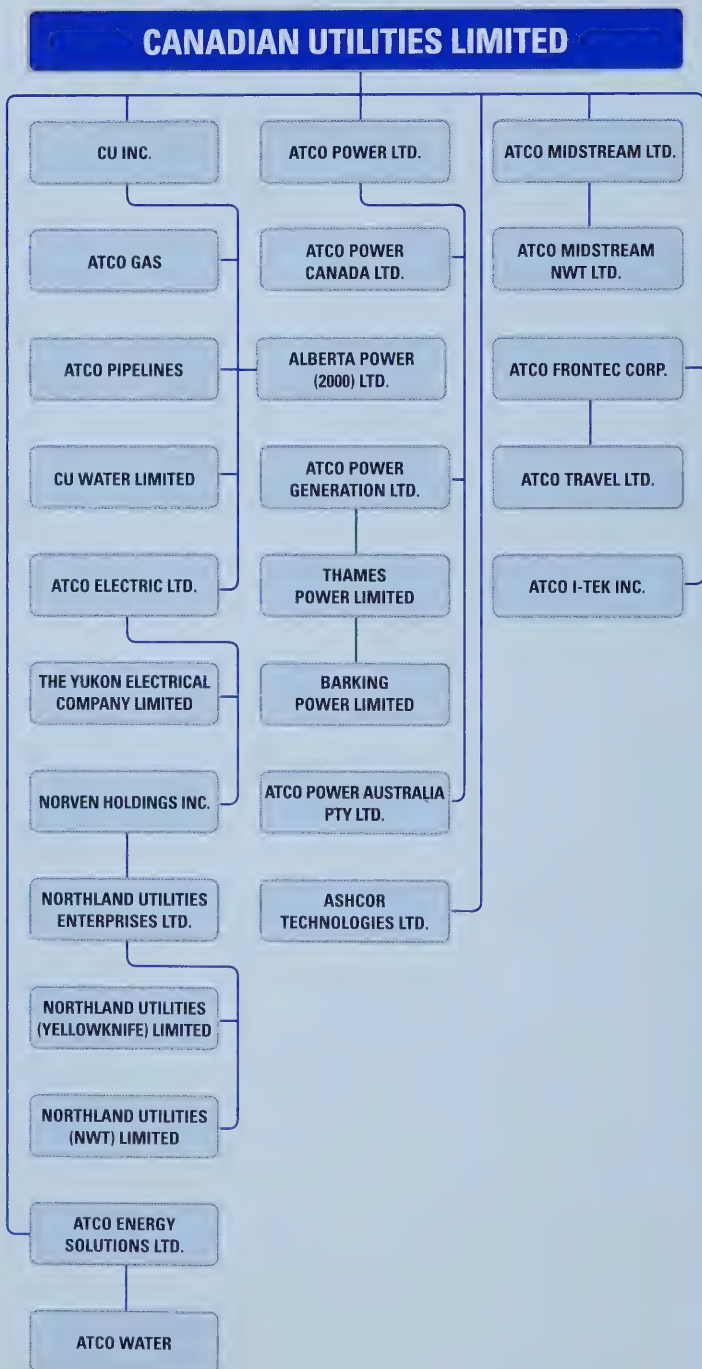
Printed in Canada

CU

Canadian Utilities Limited

ORGANIZATION CHART



Financial Highlights

CONSOLIDATED ANNUAL RESULTS

	YEAR ENDED DECEMBER 31	
(millions of Canadian dollars except per share data)	**2008**	2007
FINANCIAL		
Revenues	**2,778.9**	2,404.9
Earnings attributable to Class A and Class B shares	**413.1**	386.7
Adjusted Earnings*	**401.8**	343.8
Total assets	**7,864.4**	7,305.2
Class A and Class B share owners' equity	**2,751.7**	2,521.7
Funds generated by operations*	**804.6**	725.9
Capital expenditures	**1,010.9**	700.8
CLASS A NON-VOTING & CLASS B VOTING SHARE DATA		
Earnings per share	**3.29**	3.08
Diluted earnings per share	**3.28**	3.07
Adjusted earnings per share*	**3.20**	2.74
Dividends paid per share	**1.33**	1.25
Equity per share	**21.92**	20.13
Shares outstanding (thousands)	**125,510**	125,295
Weighted average shares outstanding (thousands)	**125,408**	125,409

* The above data (other than adjusted earnings, adjusted earnings per Class A and Class B shares and funds generated by operations) has been extracted from the financial statements which have been prepared in accordance with Generally Accepted Accounting Principles and the reporting currency is the Canadian dollar.

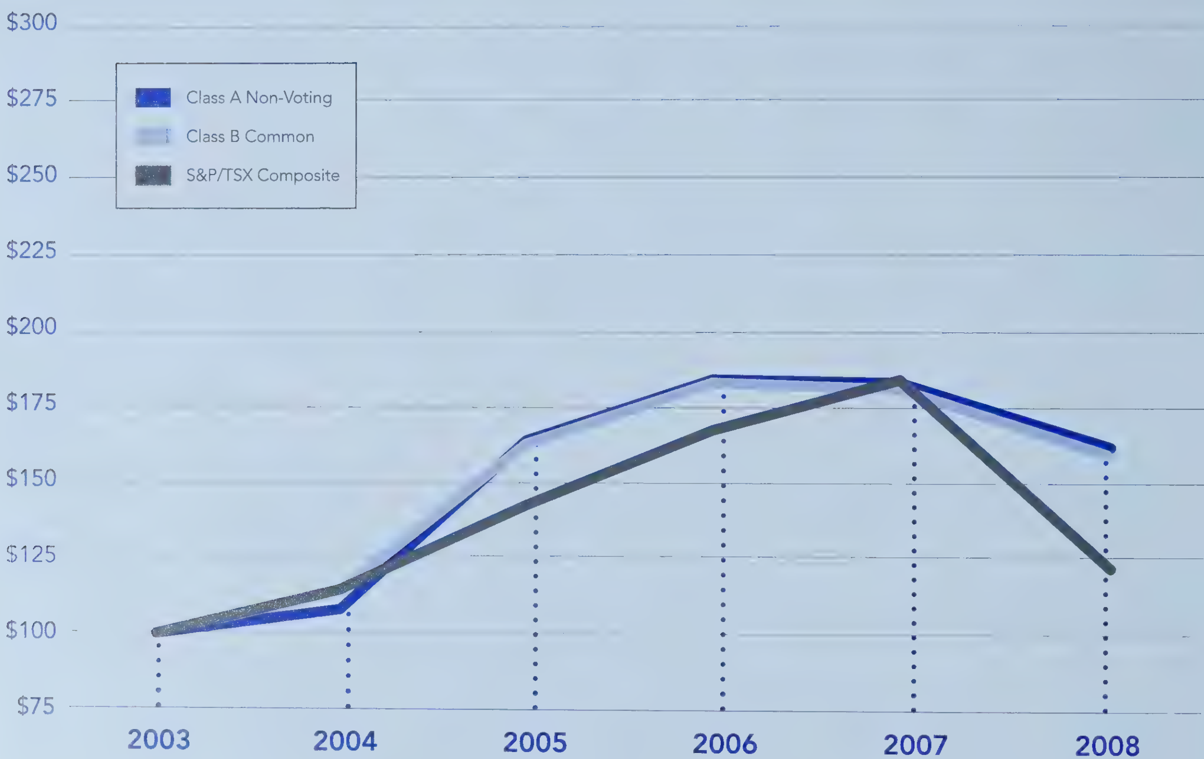
For further information please see Canadian Utilities Limited Consolidated Financial Statements - www.sedar.com

FORWARD-LOOKING INFORMATION:

Certain statements contained in this Annual Report constitute forward-looking information. Forward-looking information is often, but not always, identified by the use of words such as "anticipate", "plan", "estimate", "expect", "may", "will", "intend", "should", and similar expressions. Forward-looking information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information. The Company believes that the expectations reflected in the forward-looking information are reasonable, but no assurance can be given that these expectations will prove to be correct and such forward-looking information should not be unduly relied upon.

Five-Year Total Return on $100 Investment

CANADIAN UTILITIES LIMITED CLASS A NON-VOTING AND CLASS B COMMON SHARES



Canadian Utilities Limited Share Ownership

It is important for prospective owners to understand that Canadian Utilities Limited is a diversified group of companies principally controlled by ATCO Ltd., which in turn is principally controlled by Sentgraf, a Southern family holding company.

It is also important for present and prospective share owners to understand that Canadian Utilities share registry has both non-voting and voting common shares.

	COMPOUND GROWTH RATE	CUMULATIVE RETURN
Class A Non-Voting	10.4%	$164
Class B Common	10.1%	$162
S&P/TSX Composite	4.2%	$123

The graph compares the cumulative share owner return over the last five years on the Class A Non-Voting and Class B Common shares of the Corporation (assuming reinvestment of dividends) with the cumulative total return of the S&P/TSX composite index.

Chairman's Letter to Share Owners

I commend you to your President's letter which follows.

On behalf of the Board of Directors, we would like to compliment in the most genuine way possible, our President, her Executive team and the people of Canadian Utilities, not only for the record results which they are reporting, but also on the effectiveness of their transgenerational philosophy and beliefs which position the company well for the economies they face today, which is something more serious than an ordinary recession.

Ordinary recessions do not bring into question the solidity and stability of the global financial system in what some might describe as a profound global financial crisis, where deleveraging of households, businesses and financial institutions alike are the driving force.

Despite unprecedented global stimulus plans, it will take some time to bring markets for all products and services back to more normalized levels when national and international economies may be considerably altered from those of the past.

Your management's performance and the group's overall position bring a quiet sense of confidence to your Board which I am sure you will share upon detailed examination of your President's Report and Management's Discussion and Analysis document.

Your Board has completed an overarching review of policies and procedures used for governing and managing our company, and your Directors have brought a new focus to the efficiency and effectiveness of our governance practices.

We have a diverse Board membership of remarkable experience and knowledge, who bring a commitment to our affairs, and guidance, not just during the formal Board and Committee sessions, but throughout the year.

Their workload is quite extraordinary when judged with respect to Directors' duties in former times and, today, when strategy, performance, regulations, policies, standards & procedures are combined with risk management, audit, and pension responsibilities, I think you can understand how fortunate we are to have such a notable roster directing our group of companies – all with a view to enabling our executives to manage and deliver the favourable outcomes that have marked our history.

We would like to welcome to our Board of Directors Dr. David Dodge, former Governor of the Bank of Canada, whose great experience and knowledge will bring a solid contribution to our Board's deliberations. Dr. Dodge has been appointed Chairman of the Company's Pension Committee.

On behalf of the Board of Directors, I would also like to thank all of the people of Canadian Utilities for their great efforts to build our enterprises, not just for the present, but for generations to come.

Respectfully submitted,

R.D. Southern

CHAIRMAN OF THE BOARD

President's Letter

For most people of the world, the cross border rippling effects of deep recessionary conditions have been disturbing and unsettling. Yet, it is against this backdrop that Canadian Utilities reported record results.

Not only are the profits and cash flows the best in our history, but they are accompanied by a sterling balance sheet and strong 'A' credit rating that should bring a sense of quiet confidence to our share owners.

May I refer you to our Chief Financial Officer's Report and those of our operations which highlight our 2008 achievements.

As I reflect upon Canadian Utilities' present strength I am drawn to the long standing 'principles of operation' in our Company, which I believe, have provided a constant, enterprise-wide awareness that such adversities as those facing the world today, were always possible. In past Reports, we have often highlighted these principles and philosophies which we have applied since our founding:

Excerpts from past ATCO Group Annual Reports:

1983

"In the face of a worldwide recession... we are pleased that the management decisions taken two years ago have allowed the Company to remain financially healthy while continuing to record acceptable profits."

"Financially, the Company remains strong with uncommitted cash reserves in excess of $100 million. The reserves are the result of a program established some three years ago to ensure the Company can meet its obligations, even if the difficulties in the economy continue."

2003

"If you will recall, the economic environment of late 2002 and early 2003 was one of caution, fragility and without question, there loomed the real possibility of recession or even deflation in the United States and Canada. Therefore, our objective for 2003 was to enhance our balance sheet."

"Your Executive Team's focus, with our Board of Directors' oversight, regarding our cash is to ensure our ability to see us through any 'rainy day' scenarios... we believe it may well be prudent to have our cash on hand, given the growing uncertainty of the economies in which we operate."

"The dominating aim which we set before us... is to have a sustainable premium Company... in every respect and we do not seek maximum growth...we seek sustainable, optimum, profitable growth... which is not quite the same thing."

2005

"Our workmanlike efforts to improve our balance sheet have continued and this important strength allows for accretive, internal or external, deployments we may wish to make in the future – or on the other hand – our balance sheet strength can provide us with a prudent reserve for more difficult times."

"Looking to the future, Directors and Officers are most conscious of an ever increasing danger to global economies and markets."

2006

"Our Directors and Officers remain aware that many of our Principal Operating Subsidiaries are cyclical in nature and results may fluctuate considerably in the future."

"Because of our transgenerational culture, each of our executives brings a sense of responsible ownership to steer our Companies across business cycles (and) they have worked hard to create our present financial strength."

2007

"There is little doubt that we are experiencing a slowdown in economic activity, especially in the United States, which may spread to other nations including Canada. We have proactively prepared our management teams..."

"Our disciplined approach to growth preserved an exceptionally strong balance sheet in 2007 and it is worthy to note that our credit rating upgrade occurred in a period of significant market turmoil in parallel with Canadian Utilities' $700.8 million capital program."

TODAY – 2008

Canadian Utilities completed a capital program of $1.0 billion.

Year end cash balance is $727 million.

Our 'A' credit rating remains strong.

Our equity ratio has improved over the past five years from 50 per cent to 51 per cent.

Our earnings are a record $413.1 million.

While the profundity of the change that is occurring in the economies and financial markets of the world is yet to be fully understood, your Canadian Utilities' balance sheet remains healthy, and your executive team has preemptively prepared to husband our resources and grow internally with steady improvement in our positions.

I wish to thank the more than 6,800 women and men of Canadian Utilities who continue to demonstrate their resilience and flexibility in developing innovative solutions for our operations.

The encouragement and wise counsel of our Board has given us the confidence to successfully navigate through the uncertainties of the current environment and the capacity to withstand a prolonged contraction. I believe their governance has proved irreplaceable in preparing your Management Team for the road ahead.

Sincerely yours,

N.C. South

N.C. Southern
DEPUTY CHAIR, PRESIDENT & CHIEF EXECUTIVE OFFICER

Business Challenges for Investor-Owned Utilities

Siegfried Kiefer, Managing Director, Utilities & Chief Information Officer, shares his thoughts about the business challenges facing investor-owned utilities in the current economic climate.

The economic downturn in 2008 has impacted all businesses and investor-owned utilities are presented with some unique circumstances and significant challenges. Addressing them will require flexibility, adaptability, and most importantly, a balanced approach by utility management and regulators.

Regulatory Flexibility

The cornerstone of a successful regulatory framework is the ability to approve rates based upon forecasts of the required costs and investments of the utility, and then providing appropriate incentive for management to ensure that costs and investments are incurred as efficiently and effectively as possible while maintaining safe, reliable service to the customer.

In today's economic environment, what was forecast only a few short months ago may be dramatically different today. As a result, our management is adapting their actions and plans to meet the changing circumstance. Measuring the effectiveness of management's performance will be an important factor for regulators to consider when reviewing the utilities' expenditures and investments.

Our utilities are pleased with the positive steps the Alberta Utilities Commission is taking to create an adaptable regulatory framework capable of addressing the current challenges.

Capital Investment

Financial strength and capability will be key as governments will look to the utility companies to undertake large provincial and national infrastructure projects that are designed to stimulate the economy and create the building blocks for future economic development.

Large utility infrastructure projects are capital intensive, with major projects taking several years to complete and costing hundreds of millions of dollars. As a result, the costs to finance these

initiatives comprise a large portion of the total costs over the forty or fifty year life of these assets.

The global financial turmoil struck dramatically in September 2008 with a dramatic re-pricing of risk in bond and equity markets. Credit ratings are having a substantial impact on the risk premiums being charged. It is now even more important that investor-owned utilities have the appropriate capital structure and return on equity to maintain a strong credit rating. All credit markets and lenders are insisting on adequate interest coverage if they are to lend monies at attractive rates.

Having just completed a year of record capital investment, with the prospect of even larger infrastructure investment in the years ahead, it is imperative that the total cost of financing these long-term assets be optimized, so that customer rates can be kept low over time.

Environmental Improvements

Environmental concerns for carbon based energy are increasing. All utilities must find ways to reduce their own environmental footprint and assist customers in finding effective solutions to conserve on their energy use and to utilize innovative and alternative energy sources to meet their needs.

Our utility companies are taking a leadership role in providing consumer education on energy conservation and energy efficiency methods. There are not many businesses where it makes sense to help customers use less of your products and services. However, the regulator has supported the efforts we are taking to educate our customers through province-wide school programs, an energy education call centre and in-home evaluations of energy efficiency. These programs allow us to build on the trusted relationships with our customers and positions us to play a critical role in implementing the technologies of the future.

The introduction of new technologies, like smart meters that provide better service and more information to customers, will assist them in managing their energy consumption. Our utilities will work collaboratively with the regulator to embrace these new technologies and assist in the introduction of alternative energy solutions such as solar and geothermal to reduce our collective impact on the environment. While some of these solutions are more costly than traditional methods today, they will become more cost effective if we invest in their development and implementation.

It is extremely important that industry, government, and regulators continue to work together to properly and effectively manage these important business challenges during these complex economic times so that Alberta is well positioned with its utility infrastructure when recovery occurs.

ATCO Gas Grows with Innovative Programs and Projects

Service, innovation and growth all describe ATCO Gas in 2008. In addition to providing the safe, reliable and cost-effective distribution of natural gas Albertans have depended on for nearly a century, the year marked a major safety campaign, the creation of another alternative energy project and record capital expansion.

The company also completed the most comprehensive General Rate Application in its history, establishing the amount of revenue ATCO Gas can recover through distribution rates.

Serving more than one million customers, ATCO Gas is the largest natural gas utility in the province. Its natural gas delivery system consists of more than 37,000 kilometres of pipeline.

Faced with robust provincial growth, ATCO Gas responded to nearly 600,000 service calls and completed nearly 620,000 jobs including equipment and appliance inspections, meter installations and moves, and emergency response to gas odours and carbon monoxide calls. It also launched a province-wide campaign aimed at reducing an increasing number of preventable, dangerous natural gas line hits. Most of those hits were caused by contractors and homeowners who did not call for line locates before excavating.

"The safety of our customers, employees, contractors and company assets is a core value for ATCO Gas," said ATCO Gas President, Brian Hahn. "I am optimistic that our damage prevention campaign has made a strong impression with contractors, excavators and homeowners. In 2008, we saw 124 fewer hit gas lines than in 2007 – a 12 per cent decrease in hit lines province-wide." ATCO Gas was also recognized for safety leadership by the Canadian Gas Association.

Mr. Hahn succeeded Jerome Engler who retired in 2008. Mr. Engler worked for ATCO Gas for 31 years and served as President for the last decade. Mr. Engler's strategic thinking, innovative personnel initiatives and unprecedented capital expenditure programs effectively led the company through never-before-seen economic growth in Alberta.

Strong utility asset growth continued in 2008, pushing expansive capital expenditures to a record $250 million. Expenditures included continuation of the multi-year Meter Relocation and Replacement Project – one of the most aggressive capital projects in ATCO Gas' history. By the end of the year, approximately 100,000 additional meters had been moved from inside homes and buildings to the outside. In addition to providing easier access to gas meters to ensure accurate, timely billing, the project improves safety for meter readers. The project is expected to conclude in 2010.

"This capital growth is required to provide customers with the highest quality service," said Mr. Hahn. "It ensures our existing and new customers will continue to receive safe, reliable delivery of natural gas."

PHOTO • Chauntel Stang (L) and Chris Uson (R), meter readers from the Edmonton Service Centre, record natural gas consumption readings at a large condominium complex.

PHOTO • With a focus on customer service, ATCO Gas responds to customer needs and emergencies 24 hours a day.

ATCO Gas also provides customers with expert advice through ATCO EnergySense. (See environment feature)

Pursuing commercially viable models for alternative energy delivery was another goal of the company. In 2008, ATCO Gas partnered to begin installing alternative energy technology in southeast Calgary's community of McKenzie Towne. (See environment feature)

CU Water

The company, which supplies treated water to rural Alberta customers and small towns east of Edmonton, is now directly serving approximately 1,140 customers through its transmission network. In addition to serving communities along the transmission pipeline, approximately 200 kilometres of distribution pipeline serve rural subdivisions and intensive livestock operations.

CU Water also provides bulk water delivery. Bulk water sales were made to 17 water haulers and to the towns of Tofield and Viking – two of the company's largest customers.

The operations of CU Water are subject to regulation by the Alberta Utilities Commission (AUC). Twenty-four-hour a day monitoring and testing ensures the highest quality drinking water. In 2008, the company continued to achieve zero lost-time injuries for a fifth consecutive year.

Theatre Delivers Safe Energy to Students

Wrapped in laughter and fun, the superheroes of ATCO Energy Theatre's SuperPower! delivers important safety messages to children across Alberta. The spring and fall tour showcased the troupe at 84 schools in 51 communities throughout Alberta.

Sponsored by ATCO Gas and ATCO Electric, each tour reached more than 10,000 students and teachers, totaling more than 20,000 young students over the year.

Featuring Power Woman, Carmen Monoxide, P-Yeww and Rocket Socket, the characters explain the need to be cautious when dealing with electricity and natural gas in an edu-tainment format.

ATCO Energy Theatre effectively teaches children both safety procedures and the science behind electricity and natural gas use.

PHOTO • Elementary school students in 51 Alberta communities learned about natural gas and electricity safety.

PHOTO • ATCO Electric power line technicians change out a transformer at the company's training centre in Nisku, Alberta.

Record Capital Growth for ATCO Electric

In 2008, ATCO Electric achieved record capital growth with capital projects totaling approximately $500 million, an increase of almost 69 per cent over the previous year. The number of customers now approaches 203,000.

Serving 245 communities in northern and east-central Alberta, ATCO Electric maintains and operates more than 69,000 kilometres of transmission and distribution power lines and also operates approximately 12,000 kilometres of distribution lines for Rural Electrification Associations.

"The magnitude of our capital program and the demand it creates for specialized engineering and construction skills requires innovative solutions to get this work done safely and efficiently," said ATCO Electric President, Sett Policicchio. "In 2008, as a result of our aggressive Canadian and international recruitment efforts, we hired 249 new employees. We also formed an alliance with other world-class companies to help us complete our capital work."

The company began construction of the Brintnell to Wesley Creek 240- kV transmission line that will strengthen the electrical grid in northwest Alberta. This 226-kilometre project is expected to be completed in 2010 at a cost of approximately $210 million. The Brintnell-Wesley Creek project is ATCO Electric's and Alberta's first major transmission line project since the company's award-winning Dover-Whitefish project in 2004.

To assist with engineering and construction on large transmission capital projects like the Brintnell-Wesley Line, ATCO Electric finalized an alliance with United Kingdom-based Balfour Beatty and Australia-based United Group Limited.

ATCO Electric implemented an innovative recruitment strategy to attract a high-quality workforce from Alberta, across Canada and internationally. Recruiters held events and attended career fairs throughout much of Canada, and also made several successful trips overseas.

A new service office, the company's 38th, was opened in La Crete to better serve a growing customer base in and around La Crete, Fort Vermilion and the First Nation communities of Little Red River, Tall Cree and Beaver. The opening reinforced ATCO Electric's commitment to providing customers with a high level of service, including safe and timely response to power outages.

In 2008, ATCO Electric substantially met customer in-service dates for distribution projects as part of the company's ongoing implementation of a new work process to enhance operational effectiveness. Designed to increase success at meeting in-service dates, the process since its launch in 2006 has resulted in a tripling of on-time, in-service dates met.

Building an even stronger "safety culture" at ATCO Electric continued to be of paramount importance. A world-calibre safety performance plan was introduced and safety accountabilities and safety leadership training were rolled out. Across its regionally diverse service area, covering many remote and rural locations, ATCO Electric achieved six months of operations without a single lost-time incident. This accomplishment is attributed to the company's aggressive safety initiatives.

Northland Utilities

The Government of the Northwest Territories (NWT) granted Northland Utilities a new franchise for an area on the old Pine Point Mine site located on the south shore of Great Slave Lake. The first of its kind granted in recent NWT history, the franchise allows the company to serve an industrial customer in the future.

Northland Utilities, both in Yellowknife and Hay River, implemented a fully-integrated billing system. Northland Utilities (Yellowknife) recorded no lost-time incidents in 2008.

Northland Utilities provides electricity to more than 10,000 customers in nine communities in the Northwest Territories.

Yukon Electrical

The company successfully implemented a new fully-integrated billing system offering more than 15,000 customers in 19 Yukon communities additional options and enhancements. Yukon Electrical also achieved a record of no lost-time incidents in 2008.

PHOTO • Larson Yellowbird, a NAIT student, worked as a summer student in the ATCO Electric 2008 pilot program to complement his technical background in drafting and engineering technology.

Aboriginal Summer Student Employment Program a Success

ATCO Electric's strong commitment to building mutually beneficial relationships with Aboriginal communities throughout its service area led to a new pilot program for Aboriginal post-secondary students.

The Aboriginal Summer Student Pilot Program was designed to provide meaningful summer placements for Aboriginal students with the goal of leading to future summer placements and/or permanent employment. It was also designed to promote ATCO Electric, within aboriginal communities, as a great company to work for.

Three post-secondary Aboriginal students participated in the 2008 pilot: Tara Kappo, Nathan Coutu, and Larson Yellowbird. Tara went on to accept a full-time position with ATCO Electric's Aboriginal relations team, while continuing her studies at the University of Alberta. Nathan's supervisor provided him with a conditional "letter of offer" to return to ATCO Electric full time upon his graduation in 2009 as a telecommunications technologist. Larson has returned to his studies at Northern Alberta Institute of Technology (NAIT) and will be exploring summer placement in 2009 to complement his technical background in drafting and engineering technology.

The program will continue in 2009 as a part of ATCO Electric's Aboriginal recruitment efforts.

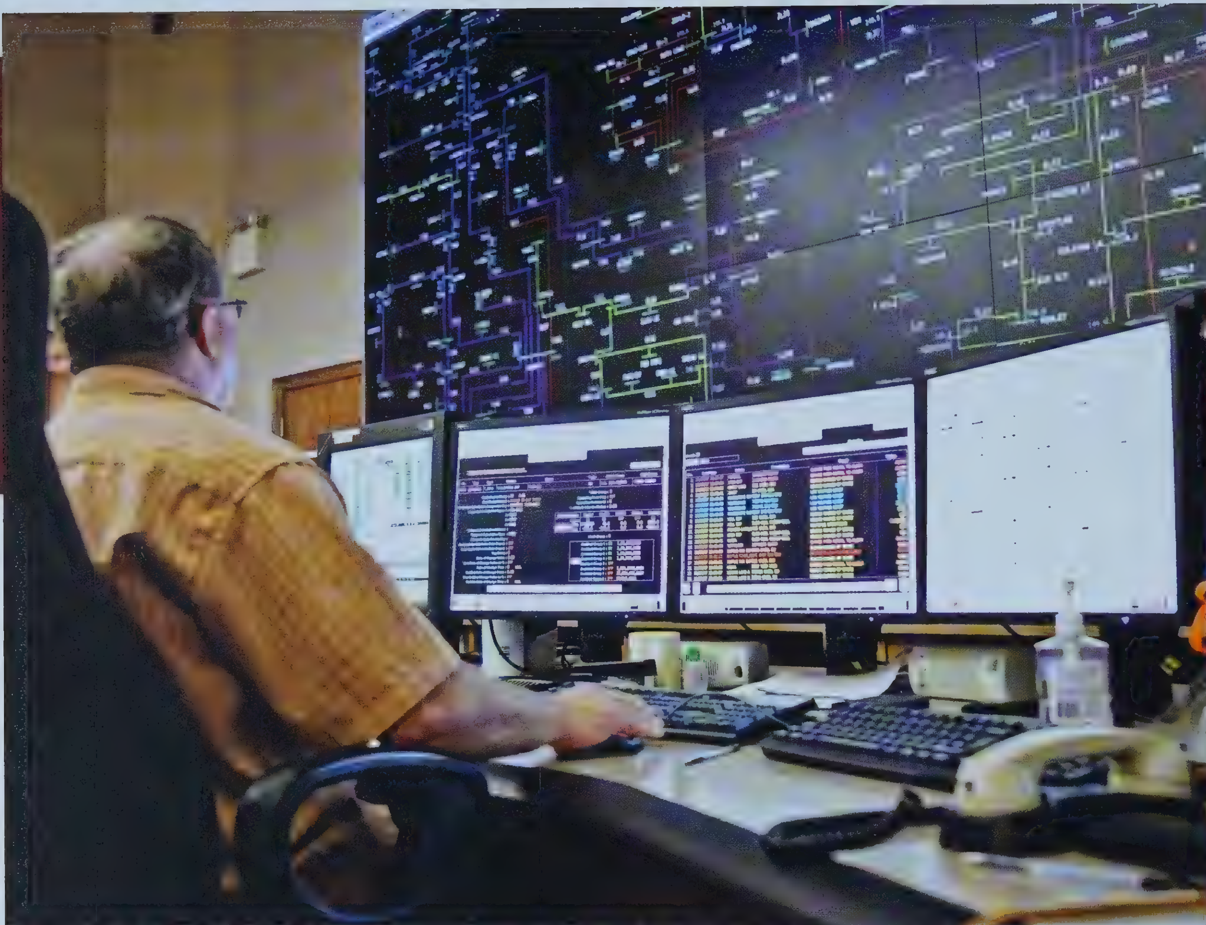


PHOTO • The Transmission System Control Centre that operates and monitors ATCO Electric's transmission system is located in Vegreville adjacent to the new Distribution Control Centre that is providing similar operational support for the distribution system.

Technology Improves Customer Service

ATCO Electric implemented advanced technology to provide its people with better information, more tools and more time so that they can continue to provide excellent, reliable service to customers.

The opening of the Distribution Control Centre in Vegreville, Alberta, will significantly advance how work is managed across ATCO Electric's service territory.

Laptop computers mounted on employee vehicles were rolled out to service staff and field service representatives. Networked to the Distribution Control Centre, the computers are linked to the company's asset management database, which tracks the age, maintenance record and location of every power pole and line in the ATCO Electric delivery system. The computers also have a Geographic Information System viewer installed, which enables service staff to view digitized maps of the entire distribution system.

ATCO Electric purchased Work Force Management and Outage Management, two software systems that will enable the company to operate more efficiently and provide exceptional customer service.

Work Force Management software allows field-based service staff to access essential customer information and site references, see meter readings and order history, and enter work and customer updates on their computers. As a result, staff can respond quicker to customer and retailer requests while dramatically reducing the amount of manual work and paperwork required.

ATCO Electric worked closely with ATCO I-Tek to successfully implement Work Force Management software in Alberta's Stettler district and at the Distribution Control Centre. This pilot project was the initial phase of a multi-phased implementation project. Future project phases include implementing Work Force Management in the rest of ATCO Electric's service territory and implementing Outage Management.

Outage Management software helps service staff to quickly and accurately predict the location of an open switch, improving outage response time and efficiency while enhancing safety and reducing costs.

PHOTO • ATCO I-Tek and ATCO Electric implemented Work Force Management, an integrated software solution that enables field service staff, like Rene Hebert, to receive orders in real time in the field, leading to improved efficiency and quicker response.

Providing Exceptional Service Key to ATCO I-Tek Success

ATCO I-Tek delivers exceptional billing flexibility, superior customer care and reliable information technology solutions to a diverse group of clients worldwide.

For a third consecutive year, ATCO I-Tek's distribution call centre, which serves ATCO Gas and ATCO Electric customers, achieved the "highest customer satisfaction" award for an energy call centre in North America from Service Quality Measurement (SQM) Group, an independent research company specializing in call centre quality assurance.

In 2008, the services provided to more than two million utility and retail customers in Alberta were expanded to include new customers in British Columbia and Ontario. Timely and efficient workforce planning was key to ATCO I-Tek's ability to quickly and effectively respond to meet the business needs of its clients.

Among the many successful business application projects undertaken by ATCO I-Tek in 2008 was the implementation of ATCO Customer Information System (CIS)—a meter to statement system—for Northland Utilities in Yellowknife and Hay River, and Yukon Electrical. ATCO I-Tek collaborated with the client teams to ensure conversions and transitions continued to meet each of the client company's unique Service Terms and Conditions.

In addition, ATCO I-Tek and ATCO Electric successfully implemented Work Force Management, an integrated software solution.

"One of the biggest benefits we bring to clients like ATCO Electric and the North of 60 team is the ability to understand their business needs and complex processes and translate them into the right business solution—whether it's a large-scale software implementation to automate processes and improve customer service capabilities, or a conversion to a fully-integrated billing system," said ATCO I-Tek President, Bobbi Lambright.

ATCO I-Tek continued delivering reliable technology services to its diverse client base including network and major application connectivity and support to its global clients. Backed by high-calibre support teams, the ATCO I-Tek Customer Support Centre handled more than 75,000 IT client requests achieving a satisfaction rating of 97 per cent on customer feedback surveys. The support teams, once again, consistently met an extensive list of client service level and control requirements. ATCO I-Tek conducted several successful Disaster Recovery exercises, including its 25th annual Enterprise server exercise and distributed systems disaster recovery programs.

Celebrating the North

2008 ARCTIC WINTER GAMES - A TRUE SHOWCASE OF EXCELLENCE

A special commemorative pin was designed to celebrate the company's involvement with the Games. Every participating athlete received a pin.

The 2008 Arctic Winter Games held March 9-15 in Yellowknife were a magical showcase of the history, culture, vibrancy and people of the North.

From sponsoring a spectacular opening cultural gala to providing internet cafes where visitors and athletes alike shared their unique experiences with friends, family, and the world, Canadian Utilities' (CU) people contributed to the Games' overwhelming success.

The Games offered an unrivaled cultural festival, with ATCO the presenting sponsor. Eight locations around the city featured photography, film making, performances and sculptures created from recycled material.

CU companies in Yellowknife wrapped their buildings in colourful pageantry. Northland Utilities provided electrical services and the people of ATCO Frontec volunteered their logistics expertise.

ATCO Structures set up modular units for use as showers and washrooms for the athletes as well as units at various event locations. The 100 computer laptops ATCO I-Tek provided during the Games were donated for use at local schools after the Games.

The Games featured athletes from the circumpolar regions of Alaska, Northern Alberta, Greenland, Nunavut, Northwest Territories, Nunavik-Quebec, Russia/Yamal-Nenets, Sami and Yukon Territories.

It was an experience neither the athletes nor the North will likely ever forget.

PHOTO • As sponsor of the Medal Presentation ceremonies, ATCO designed and provided the podium signage.

PHOTO • ATCO banners appeared at cultural event locations throughout Yellowknife.

• Modular units provided by ATCO Structures were at various
for use by athletes.

• The 2008 Arctic Winter Games were a celebration of
l culture.

Yukon Legend Returns to the Waterways

Yukon Electrical Company relaunched a Northern Canadian legend when the fabled M.V. Dorothy re-entered the Yukon River at a ribbon-cutting ceremony in July.

The 31-foot vessel, first launched in 1932, was purchased in 1962 by a former Canadian Utilities transmission and distribution engineer who moved north to manage Yukon Electrical. The M.V. Dorothy was initially purchased to facilitate inspection of future hydro sites.

Although the vessel sank at least three times during its lengthy service, it is now enjoying a renaissance on Schwatka Lake near Whitehorse and along the Yukon River after a couple of decades in dry dock.

The refurbished vessel, whose handsome oak frame, cedar planking and old-growth fir glowed in the bright sunshine of a perfect summer's day, was returned to the water in style with a celebration worthy of its long history.

The M.V. Dorothy will be used for recognition outings, to entertain customers and in conjunction with historical events in the Yukon.

PHOTO • Over eight decades the M.V. Dorothy was used [illegible] Whitehorse and was [illegible] by the United States Army during World War II.

A Year of Milestones for ATCO Pipelines

ATCO Pipelines controls more than 8,440 kilometres of pipeline in Alberta and more than 200 receipt points. The company owns and operates natural gas transportation facilities throughout the province and is an integral part of the province's gas transmission system.

The year marked a significant milestone in the execution of an arrangement with TransCanada's wholly owned subsidiary, NOVA Gas Transmission Ltd. The proposed arrangement, currently under regulatory review, will see the two companies combine physical assets under a single rates and services structure. Customers will interface with a single commercial entity with each company separately managing assets within distinct operating territories in the province.

"It is expected that the proposed model will end duplicate tolling and operational activities and will result in more efficient regulatory processes," said Bob Myles, President, ATCO Pipelines. "It is also intended to add value to customers as a result of seamless, efficient service throughout Alberta."

During the ATCO Pipelines General Rate Application process last year, customers gave unanimous approval to a negotiated revenue requirement settlement for 2008 and 2009. This settlement has now been filed with the AUC and awaits approval.

Processes and communications were also improved during the year with the opening of the new ATCO Pipelines office building in Edmonton. The 30,780 square foot office building brings together employees involved in operations, engineering projects, construction and system control monitoring.

ATCO Pipelines spent significant capital upgrading and replacing facilities again this year. The largest project in 2008 was the first of a three-year phased plan to replace the Southern Extension Pipeline between Red Deer and Viking. The pipeline was originally installed between 1945 and 1946.

PHOTO • Revenue growth combined with solid earnings contributed to overall success at ATCO Pipelines, which owns and operates natural gas transportation facilities throughout Alberta.

New focus behind ATCO Energy Solutions

A new name and a renewed business focus led to the creation of ATCO Energy Solutions in early 2008.

ATCO Energy Solutions, formerly ATCO Utility Services, provides value-added infrastructure and services to both municipal and industrial customers. Services include pipelines, water and wastewater treatment, high-voltage industrial systems and hydrocarbon storage, including hydrogen.

The new name reflects the broader nature of the non-regulated projects being undertaken by the company.

ATCO Water provides fresh approach

ATCO Water, a division of ATCO Energy Solutions, was publicly launched in October at the Alberta Urban Municipalities Association (AUMA) Convention in Edmonton.

ATCO Water is focused on water and wastewater opportunities outside the scope of CU Water's existing regulated service offerings. ATCO Water provides operations and infrastructure solutions to both industrial and municipal customers.

Projects are already underway, the most notable of which is a partnership agreement with GE Water and Process Technologies (GE). The partnership allows ATCO Water to access GE's leading purification and advanced recycling technologies. The combined technical strength of GE and operational excellence of ATCO Water is designed to ensure customers receive the very best in water services.

PHOTO • ATCO Water will build and operate facilities in Alberta and internationally.

Corporate Expertise Key to ATCO Travel

PHOTO • ATCO Travel celebrated its 30th anniversary in 2008. With offices in Calgary, Edmonton and Ottawa, ATCO Travel performed more than 120,000 travel transactions last year.

ATCO Travel experienced growth with its core corporate clients which, in addition to ATCO Group, included large organizations in the resource, aviation services and construction sectors. The complementary business activities of Group and Vacation Travel also grew with increased demand for tailored travel arrangements.

To harness technological innovations in the travel management industry, ATCO Travel completed an evaluation of new corporate and leisure on-line self-booking tools. The selected solutions, designed to provide clients with lower travel booking costs as well as increased flexibility and convenience, will be available in early 2009.

ATCO Travel provides clients with superior quality and personalized service in corporate travel management and vacation services.

Finding and Supporting Great People - a CU Strength

Intensified and sustained commitment to the success of people across CU was demonstrated in 2008 through focused new investment in advanced human resources technology and innovative programs.

CU completed the business planning process to implement an enterprise-wide human resources technology system that can be leveraged corporately and by all diverse principal operating companies.

"This system is the foundation for human resource programs and initiatives and integral to ensuring CU has the people and skills to be successful in the future," said Erhard Kiefer, Group Vice President, Human Resources & Corporate Services.

People from across CU were involved in the development of this project to guarantee that the system meets the unique needs and complexities of each CU company while offering a consistent, efficient platform for human resource processes and information.

During the year, enhancements to the ATCO Careers website attracted top talent. Improvements to the site's functionality and ease of navigation enriched the online career search experience for candidates. In addition, the look and feel of ATCO Careers was refreshed, incorporating photographs of employees with accompanying testimonials. The refreshed site reveals the range of career opportunities available across Canadian Utilities.

The initiative was backed by an extensive advertising program, resulting in a large increase in the number of qualified applicants for the posted career offerings.

Recognizing the importance of developing top leadership talent to support both employees' career development and the company's growth, CU has begun the implementation of a comprehensive leadership development program. Initial program components are targeted at various employee groups based on their developmental requirements and include customized and standard course offerings, mentoring, leadership transitions and experiential training.

PHOTO • ATCO Power's Professional New Graduate Program provides a 20-month rotation designed to give participants broad experience in the company. From left: Jeff Pejs, Mechanical Engineer in Training (EIT), Ramiro Da Corte, Electrical EIT, Visu Viswanathan, Electrical EIT, Richard Wong, Mechanical EIT and Allan Ng, Junior Accountant.

ATCO Power Adds New Facilities to Meet Demand

ATCO Power is a world-class developer, construction manager, owner and operator of technologically advanced and environmentally progressive independent power plants in Canada, the United Kingdom and Australia.

In 2008, ATCO Power completed construction of its new 45-MW clean natural gas-fired power plant in Valleyview, Alberta while also launching development of a third generating facility in Australia.

Completed a month ahead of schedule, Valleyview II was designed as a "peaking facility" to bolster provincial grid supply while providing quick access to additional power when needed. Built within budget and capable of generating sufficient electricity to power more than 36,000 homes, the plant is 100 per cent owned by ATCO Power and ATCO Resources.

It is located adjacent to Valleyview I, one of the first plants built in Alberta when ATCO Power was initially formed in 1988 to pursue opportunities in the deregulated electricity marketplace.

In November, ATCO Power Australia Pty Ltd, announced construction of a new energy efficient 86-MW natural gas-fired power station for Horizon Power adjacent to Horizon's Karratha Terminal in the Pilbara region of Western Australia. It is the company's 20th facility.

ATCO Power will design, build, own and operate the Karratha Power Station, with the power sold under a 20-year Power Purchase Agreement (PPA) with Horizon Power.

The power plant is a two-unit GE LM6000 natural gas turbine simple cycle facility that will produce power using approximately 35 per cent less gas and creating 35 per cent lower greenhouse gas emissions for each kilowatt hour compared to Horizon Power's existing generation in the Pilbara region.

PHOTO • ATCO Power added a second LM6000 gas turbine and generator package at the Valleyview, Alberta peaking facility in 2008, doubling its capacity to 90-MW and providing additional quick-start ability to support Alberta's growing needs.

The company also operates a 180-MW cogeneration facility in Adelaide and a 33-MW cogeneration plant at Bulwer Island in Brisbane.

"Both Western Australia and Alberta have experienced high levels of activity in the resource development sector which has contributed to the need for additional power generation," said Rick Brouwer, President, ATCO Power, noting the corporation's board of directors held meetings in Australia in 2008 to view operations first-hand. "These additional generating facilities deliver greater reliability in this remote area of Western Australia."

Additionally, ATCO Power with partner TransCanada Corp. is conducting a feasibility study and preliminary public consultations regarding potential development of a run-of-river hydroelectric project on the Slave River in northeast Alberta.

The Slave River concept is at a very preliminary stage and would require significant transmission upgrades if it were to proceed. Mr. Brouwer said a strong benefit of the project is that it delivers emissions-free generation in support of the province of Alberta's greenhouse gas reduction goals.

"The Sheerness Generating Station near Hanna, Alberta achieved its eighth consecutive year without a lost-time incident"

"If the project receives the public, government and financial support necessary, it will certainly help Alberta and Canada meet some of their environmental goals in terms of reduced greenhouse gases," added Mr. Brouwer.

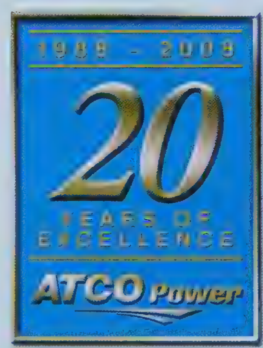
ATCO Power maintained high availability at its generating plants providing power to its respective offtakers or power grids throughout the year in all geographic operating locations.

Volatile natural gas prices and Alberta Power Pool prices, combined with ATCO Power's "asset optimization strategies" resulted in excellent performance in the Alberta market.

In 2008, ATCO Power's business development group implemented organizational changes to create a new focus on renewable projects.

CANADIAN UTILITIES' POWER GENERATION GROUP INCLUDES:

- The non-regulated supply of electricity and cogeneration steam by ATCO Power.
- The regulated supply of electricity by Alberta Power (2000) Ltd.
- The sale of ash and other combustion by-products from coal-fired generating plants by ASHCOR Technologies Ltd.



ATCO Power celebrated its 20th anniversary in 2008 with a renewed focus on Operational Excellence and a continuing commitment to sustainable growth and development.

ASHCOR Technologies

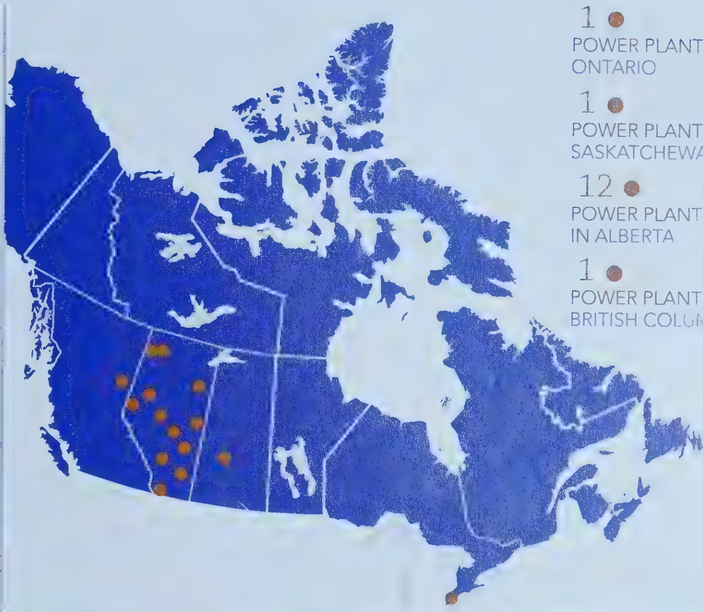
ASHCOR Technologies celebrated its 10th anniversary of operation in 2008 and 10 years of continuous growth in sales. ASHCOR markets the coal combustion products from ATCO Power's coal-fired generating stations in Alberta. By collecting the fly ash produced, and using it in new cementing materials, ASHCOR achieves two environmentally significant results: it captures a by-product that would normally go to a reclamation site and uses it in other construction material applications.
(See environment feature)

ATCO POWER – A Leader In Power Generation Worldwide

ATCO Power and its joint venture partners, operate and own 19 power plants in Canada, the United Kingdom and Australia.

2 POWER PLANTS IN UNITED KINGDOM

2 POWER PLANTS IN AUSTRALIA



1 POWER PLANT IN ONTARIO

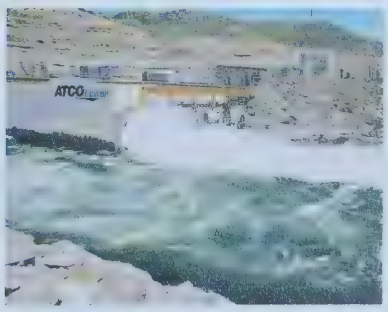
1 POWER PLANT IN SASKATCHEWAN

12 POWER PLANTS IN ALBERTA

1 POWER PLANT IN BRITISH COLUMBIA

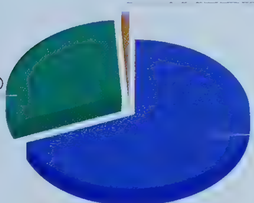
The 1,000-MW Barking Power Plant in east London uses an advanced combined-cycle technology to enhance fuel efficiency and reduce emissions.

The 180-MW Osborne Cogeneration station produces up to 1.2 million tonnes of steam each year for an adjacent manufacturing plant and approximately 10 per cent of South Australia's electricity.



The 32-MW Oldman River hydroelectric facility in southern Alberta generates clean electricity in partnership with the Piikani Nation.

ATCO Power Generation Portfolio



ATCO Power Generating Capacity

	2008	2007
Generating capacity operated (MW)	4,885	4,840
Generating capacity owned (MW)	2,503	2,467

People of CU Value Investing in their Communities

PHOTO • The ATCO Employees Participating in Communities (EPIC) program enjoyed unprecedented support in 2008, with a record donation of $2.3 million to 450 charity and community causes throughout Alberta.

CU's sustained commitment to community was demonstrated in record charitable donations as well as numerous community events and corporate partnerships.

In 2008, the people of CU participated in raising an unprecedented $2.3 million to 450 Alberta charities through the employee-led, annual fundraising initiative, ATCO Employees Participating in Communities (EPIC). This total represents an increase of more than $600,000 over the previous year.

"CU's people, through record fundraising efforts, are again making an increased contribution to support the quality of life in our communities," said Siegfried Kiefer, Managing Director, Utilities & Chief Information Officer.

The ATCO EPIC fundraising total included more than $1 million donated by CU and its parent company ATCO to match money pledged during the campaign. By absorbing administration costs internally, CU ensures that 100 per cent of funds donated through ATCO EPIC directly benefit the charitable organizations.

CU also supported hundreds of events touching all aspects of community life, including programs for youth and sports ranging from local amateur events to world-calibre international gatherings including:

- ATCO Gas supported the Alberta Winter Games in Leduc and the Alberta Summer Games in Medicine Hat.
- ATCO Frontec's donation to Future Generations Canada provides 15 Afghan families the new freedom to work and study after darkness falls. These families no longer rely on candles or toxic burning bushes to extend daylight. Solar-powered lighting allows them to work during the day and study at night – a solution that to date has transformed the lives of more than 400 families. Future Generations Canada assists in training local people to install and maintain the solar lighting system.
- ATCO Midstream provided sponsorships to a number of worthy community organizations including the Piitoayis Family School and Rainbow Society of Alberta.
- ATCO Power announced a new five-year commitment to the Botanic Gardens in Adelaide Australia. Another initiative, with a special focus on the environment, was made in support of Ducks Unlimited in Hanna, Alberta.

PHOTO • Aileen Lai, Purchasing Coordinator for ATCO Power, participates in a Day of Caring at Edmonton's 630 CHED Santas Anonymous; a program devoted to bettering the lives of less fortunate children.

PHOTO • [illegible]

CU COMPANIES CHAMPION EXCELLENCE AT 2008 SASKATCHEWAN SUMMER GAMES

ATCO Electric and ATCO Gas, along with volunteers from other ATCO companies, demonstrated their commitment to excellence in helping make the 2008 Saskatchewan Summer Games an outstanding success.

Excellence and Beyond was the Games' theme as 2,000 young athletes, coaches, managers and spectators descended on both sides of the Alberta-Saskatchewan border at Lloydminster for the August celebration of sport.

In addition to employees and families volunteering during the Games, ATCO Gas and ATCO Electric were title sponsors of the Torch Relay and co-sponsors of both the Opening and Closing Ceremonies.

Also provided were pop-up canopies, a special events trailer and 30-foot inflatable tents. ATCO Gas staff created six custom-crafted hand-held torches for the Games that remain as a legacy gift to the community.

Held every four years, the summer games bring together young athletes from Saskatchewan's nine sport zones to participate in archery, athletics, baseball, canoe/kayak, cycling, golf, lacrosse, soccer, softball, swimming, synchronized swimming and triathlon.

CU companies and their people have a long history of contributing to events and charitable organizations where they live and work.

ATCO Frontec Reputation Grows Worldwide

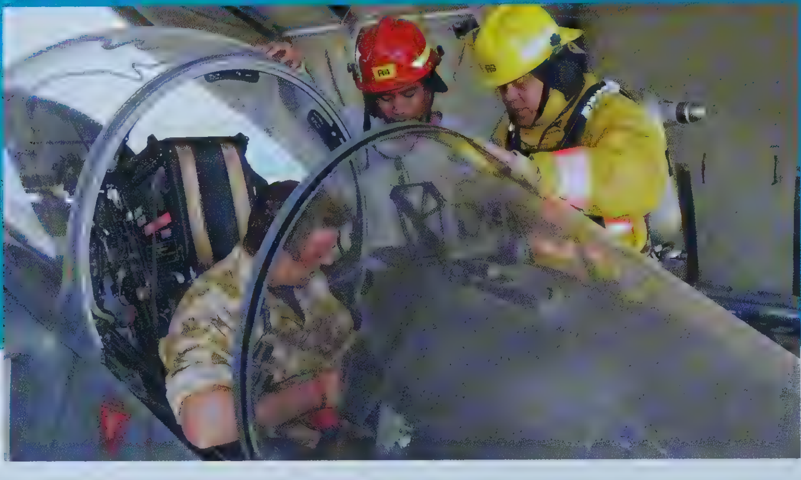


PHOTO • ATCO Frontec firefighters (from left to right) [illegible] and [illegible] are briefed by Petty Officer [illegible] Reynolds of the British Royal Air Force on the emergency rescue procedures for the Harrier jet which flies out of Kandahar.

ATCO Frontec grew its national and international reputation for servicing expertise by securing several contracts in 2008.

With 21 offices around the world, ATCO Frontec specializes in the rapid mobilization and delivery of site support and camp services to the resource, defence, transportation and telecommunications sectors.

Internationally, activity significantly increased at the Kandahar Airfield in Afghanistan, where the company has provided site support service to NATO since 2007.

Among its new ventures, ATCO Frontec assumed responsibility for waste management from its subcontractor at Kandahar. The company purchased capital equipment previously owned by the subcontractor, added several key pieces of equipment, hired additional staff with appropriate qualifications, and contracted a specialist to remove hazardous material from Kandahar Airfield.

"We continued to build our track record for delivering a wide range of services in remote and challenging operational environments in 2008 – from Afghanistan to the far North," said ATCO Frontec President & Chief Operating Officer, Harry Wilmot. "Once again it was the strength and diversity of our people that allowed us to provide crucial services to our clients, often on very short notice."

A contract to support the International Security Assistance Force and Raytheon, a major American defence contractor that is providing RAID tower systems to the Kandahar Airfield operations, was also added. RAID is a persistent surveillance system consisting of infrared sensor systems elevated on a stationary platform. RAID is capable of detecting hostile troop and equipment movement at great distances.

Agreement was reached to support technology specialists MacDonald Dettwiler, which will be establishing an operation in Kandahar to support the Canadian Forces' Unmanned Vehicle Operation.

ATCO Frontec also worked with NATO Maintenance and Supply Agency to develop plans for supporting an expansion of personnel and facilities at Kandahar.

Plans to expand the combined air terminal operations and aircraft crossing services were completed with substantial increases in the scope of existing contracts.

OTHER ATCO FRONTEC HIGHLIGHTS:

- ATCO Frontec, in partnership with the Fort McKay First Nation, opened Creeburn Lake Lodge, a 500-room facility built to accommodate industry workers in Alberta's oil sands region north of Fort McMurray. Since its opening, the Lodge has been at near capacity.
- The first tenants moved into the Barge Landing Lodge operated for Suncor near the Creeburn Lake Lodge in June.
- A contract was awarded to expand Barge Landing Lodge to accommodate workers with Albian Sands Energy.

Creeburn Lake Lodge

A PARTNERSHIP IN INNOVATIVE THINKING

A few years ago ATCO Frontec saw a niche-market opportunity for independent camps that would cater to the oil sands workers seeking accommodation.

ATCO Frontec found a committed, talented business partner in the Fort McKay First Nation Community – a First Nation that also saw opportunity in the venture.

Both parties brought an 'in it for the long term' approach to the table. This meant not holding back, not having hidden agendas, but sitting together to talk through, to iron out any differences in approach and above all, to treat each other with respect.

The result: a joint venture project built on a shared vision that has developed into a successful working partnership in addition to a growing friendship spanning the people of both groups.

Creeburn Lake Lodge north of Fort McMurray is an impressive 500-room, full-service lodge that caters to oil sands workers. Both ATCO Frontec and Fort McKay First Nation have taken equal responsibility for designing, creating and sustaining the Lodge – a key ingredient that continues to ensure the Lodge's success.

"Creeburn Lake Lodge is yet another example of some of the progressive work our First Nation has undertaken," said Chief Jim Boucher. "We found a business partner that shares the same values ... has gained financ... skills and expertise.

Since partnering in Creel... and Fort McKay First ... ventures to meet ...

PHOTOS • Creeburn Lake Lodge, a spacious and con... 500-room full-service facility in which ATCO Frontec part... the Fort McKay First Nation, officially opened in October of 2...

PHOTO • Grand Chief Arthur Noskey of the Treaty 8 First Nations of Alberta and CU President & Chief Executive Officer Nancy Southern in May signed a Letter of Intent to explore opportunities together.

Exploring Opportunities with Treaty 8 First Nation

CU and its parent company ATCO have long recognized the importance and mutual benefits of working cooperatively, openly and effectively with First Nations, Métis Settlements, Inuit and other Aboriginal groups. Relationships and opportunities with these communities continue to positively grow, with equally impressive results for everyone involved.

Last May, with the pounding of drums and the smell of burning sweet grass in the air, CU President & Chief Executive Officer Nancy Southern and Grand Chief Arthur Noskey of the Treaty 8 First Nations of Alberta signed an historic Letter of Intent.

The Letter of Intent, designed to guide the relationship process and eventually lead to more prosperous futures for both organizations, was the first of its kind for Treaty 8 First Nations of Alberta. Core to the agreement is that the partnership is built on a foundation of mutual respect.

"This agreement sets the framework for us to work together to build sustainable economic growth and explore mutually beneficial business opportunities," said Ms. Southern. "All of our partnerships are built on the understanding of mutual respect and transparency, this one is of no exception."

Covering nearly half of Alberta, Treaty 8 First Nations of Alberta represents 23 First Nations with approximately 32,000 people within the treaty area.

"We share the value of mutual respect and trust with our new partners in pursuing a successful business and

PHOTO • Creeburn Lake Lodge received the Rewarding Partnerships Award from the Alberta Government and Alberta Chamber of Resources for excellence in innovation and best practices in Aboriginal programs. "This unique joint venture between ATCO Frontec and Fort McKay First Nation will result in many benefits for First Nations residents and industry alike," said Gene Zwozdesky, Alberta's Minister of Aboriginal Relations.

entrepreneurial future for our people," said Treaty 8 Grand Chief, Arthur Noskey. " The company's First Nation partnerships have been very successful and we look forward to working together for the long-term benefit of our people, our land, and our First Nations."

CU has a long history of mutually beneficial partnerships with aboriginal communities across North America; from Alaska to Greenland, Alberta to Inuvik and all across the North.

The Creeburn Lake Lodge Project is an example of such a successful joint venture initiative. (See feature story on page 27).

Across CU, many best practices have been adopted fr... successful joint venture projects. Experiences ... by CU's people have led to shared learning of unmatched value.

The Aboriginal Relations Team (ART) is comr... gathering these experiences and sharing ... so that lessons learned are captured and ... strengthen relationships and build new ...

This strengthened internal process has helped ... new Distribution Consultation Se... agreements between ATCO E... Nations provide a framewo... conducted, outlines an agreed fee-... and provides a means for o... both internal and external con... improved.

ART has also been involved ... Aboriginal summer employm... Electric. (See feature sto... aimed at providing me... to students who have comp... post-secondary education. Ac... opportunities are availabl... diversity awareness trainin...

In the fall, several CU employ... in the Asenewache Winewach... experience in Grande C... days, participants spent ... to stories, visiting grave sit... and sleeping in teepees. E... understanding about their ... sustain and grow these n...

PHOTO • The opportunity to learn more about Aboriginal culture was a valuable experience for CU employees who participated in the Asenewache Winewache Nation cultural camp in Grande Cache.

PHOTO • Managed by ATCO Midstream, the Carbon Storage facility, with multiple pipeline connections, plays an important role in providing customers with dependable natural gas storage services. The Carbon storage operation has been in service for more than 35 years, making it one of the more established and reliable gas storage facilities in Western Canada.

New Customers and Acquisitions Highlight Year for ATCO Midstream

2008 marked another year of record earnings for ATCO Midstream. A combination of high plant availability and high liquids prices resulted in a ninth consecutive year of earnings growth. New customers and acquisitions were highlights for the company as it expanded operations, forging new business relationships and strengthening existing ones.

With ownership or interest in 10 gathering facilities and four extraction facilities and a combined processing capability of 1.8 billion cubic feet per day, ATCO Midstream provides natural gas gathering, processing, storage and natural gas liquids solutions to the Canadian natural gas producing sector.

"Our focus on customers and our commitment to excellence in all operations are key reasons why ATCO Midstream continues to grow," said Kevin Cumming, President, noting, "We would not have had the success we did in 2008 without the dedication and expertise of the ATCO Midstream team and our partners."

In November, the company joined other Canadian Utilities companies already active in Canada's North by purchasing IPL Holdings Inc. The company was renamed to ATCO Midstream NWT Ltd. and holds a one-third interest in the Ikhil Joint Venture and one-third of Inuvik Gas Ltd.

The Ikhil Joint Venture and Inuvik Gas represent the first natural gas development project north of the Arctic Circle. Assets include two producing wells, gas gathering and processing facilities as well as a 50 kilometre pipeline to the town of Inuvik. Inuvik Gas is the sole distributor of natural gas to the town, serving more than 850 customers.

"This is an important acquisition for our company," said Mr. Cumming. "It marks ATCO Midstream's first venture North of 60 where we are pleased to be partnering with the Inuvialuit and AltaGas."

ATCO Midstream continued to show strong performance in health and safety management and efforts continue to reduce environmental impacts at company sites.

Karen M. Watson
Senior Vice President
& Chief Financial Officer

Financial Excellence 2008

CONSOLIDATED HIGHLIGHTS (Millions of Canadian dollars, except as indicated)	2008	2007
INCOME STATEMENT		
Revenues	2,778.9	[illegible]
Earnings		
Utilities	149.0	[illegible]
Power Generation	[illegible]	[illegible]
Global Enterprises	[illegible]	[illegible]
Corporate & Other & Eliminations	[illegible]	[illegible]
Earnings	413.1	[illegible]
Adjusted earnings (1)	401.8	[illegible]
BALANCE SHEET		
Cash (2)	[illegible]	[illegible]
Total Assets	[illegible]	[illegible]
Capitalization		
Long Term Debt	[illegible]	[illegible]
Non-recourse Long Term Debt	[illegible]	[illegible]
Equity Preferred Shares	[illegible]	[illegible]
Share Owners' Equity	[illegible]	[illegible]
Capitalization	[illegible]	[illegible]
CASH FLOW STATEMENT		
Funds Generated by Operations (3)	[illegible]	[illegible]
Capital Expenditures		
Utilities	[illegible]	[illegible]
Power Generation	[illegible]	[illegible]
Global Enterprises	[illegible]	[illegible]
Corporate & Other	[illegible]	[illegible]
Capital Expenditures	[illegible]	[illegible]
RATIOS		
Return on equity (%)	[illegible]	[illegible]
Earnings per share ($)	3.29	[illegible]
Adjusted Earnings per share ($) (1)	3.20	[illegible]
Dividends paid per share ($)	[illegible]	[illegible]
Equity per share ($)	[illegible]	[illegible]
Class A Non-Voting closing share price ($)	[illegible]	[illegible]
Class B Voting closing share price ($)	[illegible]	[illegible]

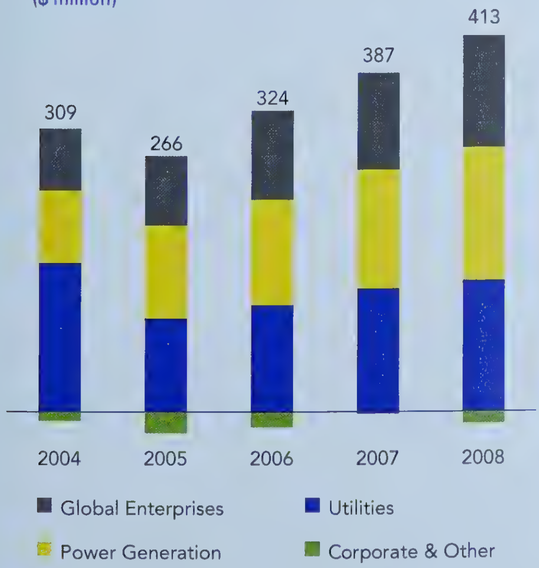
Full disclosure of all financial information is available on the SEDAR website - www.sedar.com.

Canadian Utilities' record earnings in 2008 of $413.1 million ($3.29 per share) were attributable to all three of the Company's business groups - Utilities, Power Generation and Global Enterprises.

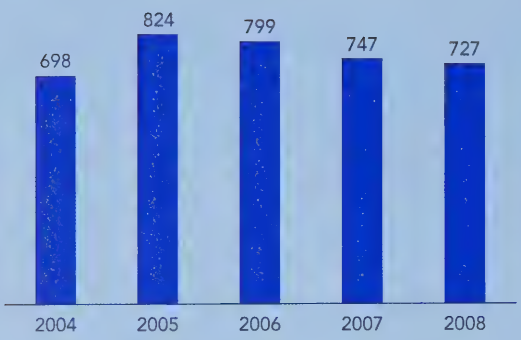
Canadian Utilities' 2008 increased revenues of $2,778.9 million, compared to 2007 of $2,404.9 million, were primarily due to increased revenue in ATCO Electric, ATCO Gas, ATCO Power and ATCO Frontec.

Canadian Utilities' adjusted earnings in 2008 were $401.8 million ($3.20 per share) compared to $343.8 million ($2.74 per share) in 2007.

Earnings Attributable to Class A & Class B Shares ($ million)



(1) Adjusted earnings are defined as earnings attributable to Class A and Class B shares after adjustment for items that are not in the normal course of business or a result of day to day operations. The majority of these adjustments in 2008 related to tax issues and an adjustment for other post employment benefits. This measure is not defined by Generally Accepted Accounting Principles and may not be comparable to similar measures used by other companies.
(2) Cash is defined as cash and short term investments less bank indebtedness.
(3) Funds generated by operations is defined as cash generated from operations before changes in non-cash working capital. This measure is not defined by Generally Accepted Accounting Principles and may not be comparable to similar measures used by other companies

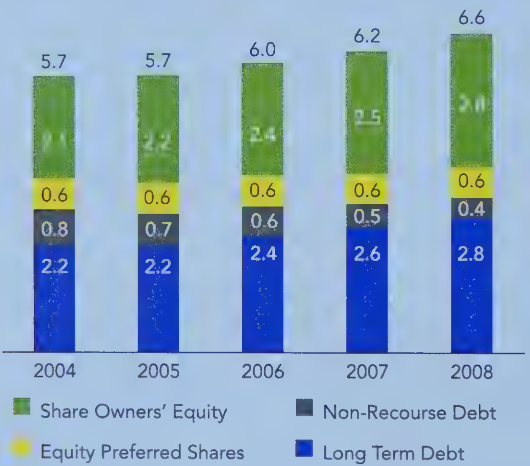


Cash ($ Millions)

Canadian Utilities' balance sheet remains strong and positions the company for future growth. Cash balances (as defined on previous page) of $726.6 million have remained relatively consistent for the last five years. In addition to this, the Company has committed and uncommitted available lines of credit of $894.7 million which can be utilized for general corporate purposes.

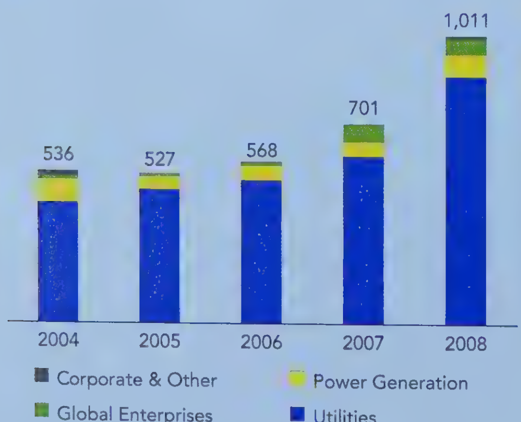
Funds Generated by Operations ($ Millions)

Funds generated by operations increased to $804.6 million in 2008 compared to $725.9 million in 2007. This increase was primarily attributable to higher earnings and increased availability incentives in Alberta Power (2000)'s power generating stations.



Capitalization ($ Billions)

Canadian Utilities share owners' equity at the end of 2008, including equity preferred shares, was $3.4 billion comparable to 2007 of $3.1 billion. The Company's non-recourse debt has also been reduced over the last five years to $0.4 billion in 2008 from $0.8 billion in 2003.

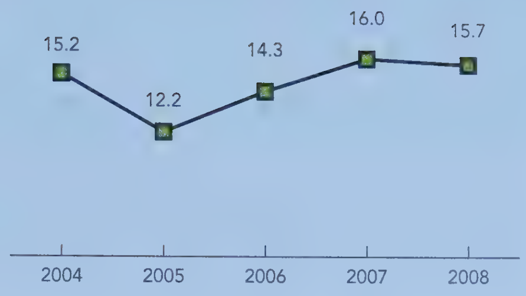


Capital Expenditures ($ Millions)

The growth in the Alberta economy has resulted in significant growth in total capital expenditures for Canadian Utilities. This growth is primarily attributable to the Utilities Business Group. The total for 2008 was $1,010.9 million compared to $700.8 million in 2007. Furthermore, capital expenditures to maintain capacity, meet planned growth, and fund future development activities are expected to be approximately $1.1 billion in 2009. The majority of these expenditures relate to the Utilities operations. Capital expenditures for the Utilities operations for 2009 to 2011 are expected to be $2.0 billion and, depending on infrastructure spending, could be as much as $4.0 billion.

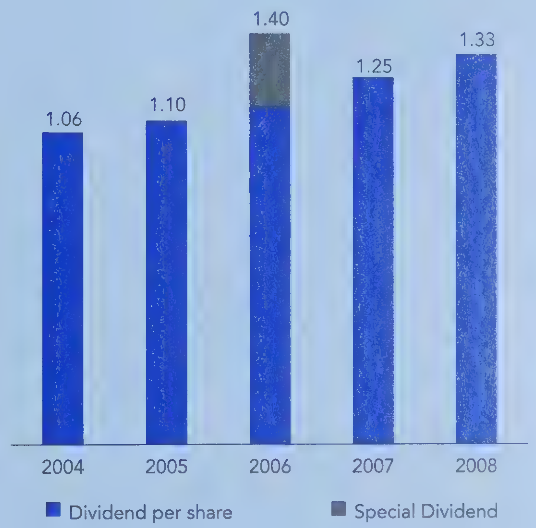
Return on Equity (%)

Return on equity for 2008 was 15.7% compared to 16.0% in 2007. This was achieved even though the regulated utilities are subject to a formula driven return on equity regime that resulted in a rate of 8.75% for 2008. Therefore, the overall Canadian Utilities rate of 15.7% was driven by results of the non-regulated entities in the Company.



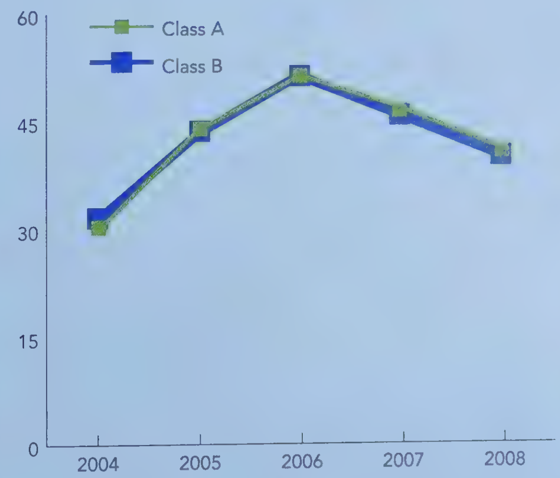
Dividends per Share ($)

Dividends paid to common shareholders were $1.33 per share in 2008. This compares to a $1.25 dividend per share in 2007. Excluding the impact of the $0.25 per share special dividend paid in 2006, dividends per share have increased each year since 1972 — 36 years.



Share Price ($)

The price of Canadian Utilities Class A and Class B shares, on the Toronto Stock Exchange, decreased from the 2007 closing price. The closing prices for Class A and Class B shares at the end of 2008 were $40.50 and $40.00 respectively compared to $46.40 and $46.00 at the end of 2007, decreases of 13%. The decrease in the closing price of Class A and Class B shares compares to a 35% decrease in the S&P/TSX Composite Index from 2007 to 2008.



Management's Responsibility for Financial Reporting

Management is responsible for the preparation of the consolidated financial statements, management's discussion and analysis of financial condition and results of operations and other financial information relating to the Corporation contained in this annual report. The consolidated financial statements have been prepared in conformity with Canadian generally accepted accounting principles using methods appropriate for the industries in which the Corporation operates and necessarily include some amounts that are based on informed judgments and best estimates of management. The financial information contained elsewhere in the annual report is consistent with that in the consolidated financial statements.

PricewaterhouseCoopers LLP, our independent auditors, are engaged to express a professional opinion on the consolidated financial statements.

Management has established internal accounting and financial reporting control systems, which are subject to periodic review by the Corporation's internal auditors, to meet its responsibility for reliable and accurate reporting. Integral to these control systems are a code of ethics and management policies that provide guidance and direction to employees, as well as a system of corporate governance that provides oversight to the Corporation's operating, reporting and risk management activities.

The Board of Directors, through its Audit Committee comprised entirely of outside Directors, oversees management's responsibilities for financial reporting. The Audit Committee meets regularly with management, the internal auditors and the independent auditors to discuss auditing and reporting on financial matters, to assure that management is carrying out its responsibilities and to review and approve the consolidated financial statements. The auditors have full and free access to the Audit Committee and management.

N.C. Southern

DEPUTY CHAIR, PRESIDENT & CHIEF EXECUTIVE OFFICER

K.M. Watson

SENIOR VICE PRESIDENT & CHIEF FINANCIAL OFFICER

February 17, 2009

Canadian Utilities Limited

CONSOLIDATED FIVE-YEAR OPERATING SUMMARY

(Millions of Canadian dollars, except as indicated)	2008	2007	2006	2005	2004
Utilities					
Natural gas distribution operations					
Purchase of property, plant and equipment	**249.7**	191.6	167.4	174.0	154.3
Pipelines (thousands of kilometres)	**37.2**	36.5	35.9	35.4	34.8
Maximum daily demand (terajoules)	**2,130**	1,819	1,861	1,919	2,049
Natural gas sold (1) (petajoules)	-	-	-	-	103
Natural gas distributed (1) (petajoules)	**238**	233	219	216	120
Total system throughput (petajoules)	**238**	233	219	216	223
Average annual use per residential customer (gigajoules)	**124**	127	126	131	134
Degree days - Edmonton (2)	**4,051**	3,992	3,819	3,641	3,985
- Calgary (3)	**4,171**	4,058	3,910	3,934	3,978
Customers at year-end (thousands)	**1,022.2**	1,001.8	969.9	939.6	914.3
Electric distribution and transmission operations					
Purchase of property, plant and equipment	**518.4**	311.8	238.1	212.2	223.4
Power lines (thousands of kilometres)	**71.5**	70.9	70.1	69.2	68.0
Electricity distributed (millions of kilowatt hours)	**10,594**	10,744	10,286	9,926	9,910
Average annual use per residential customer (kWh)	**7,666**	7,690	7,495	7,214	7,475
Customers at year-end (thousands)	**228.2**	223.0	216.3	210.9	206.2
Natural gas transmission operations					
Purchase of property, plant and equipment	**81.7**	87.1	97.7	84.3	47.9
Pipelines (thousands of kilometres)	**8.4**	8.4	8.4	8.3	8.3
Contract demand for pipelines system access (terajoules/day)	**5,034**	5,143	5,032	4,830	4,606
Power Generation					
Purchase of property, plant and equipment	**75.8**	49.2	48.1	41.2	77.0
Generating capacity operated (megawatts)	**4,885**	4,840	4,840	4,840	4,840
Generating capacity owned (megawatts)	**2,503**	2,467	2,474	2,474	2,474
Availability (%)	**93.5**	91.6	93.0	92.5	91.9
Global Enterprises					
Purchase of property, plant and equipment	**56.2**	62.7	14.2	11.9	14.5
Natural gas processed (Mmcf/day)	**435**	478	480	476	427
Natural gas gathering lines (kilometres)	**1,000**	1,000	1,000	1,000	1,000

(1) Effective May 2004, with the transfer of the retail energy supply businesses, ATCO Gas' existing sales service customers became transportation service customers.
(2) Degree days - Edmonton - are defined as the difference of the mean daily temperature from 14.5 degrees Celsius.
(3) Degree days - Calgary - are defined as the difference of the mean daily temperature from 15.5 degrees Celsius.

DIRECTORS

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Corporate Director

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Corporate Director

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President & Chief Executive Officer
Spruce Meadows

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Vice Chairman, Investment &
Corporate Banking
BMO Capital Markets

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James W. Simpson
Lead Director

Nancy C. Southern
Deputy Chair, President &
Chief Executive Officer
Canadian Utilities Limited

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Chairman of the Board of Directors
Canadian Utilities Limited

Roger J. Urwin, C.B.E., Ph. D.
Corporate Director

Charles W. Wilson
Corporate Director

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Managing Director, Utilities &
Chief Information Officer

Michael M. Shaw
Managing Director, Global Enterprises

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Resources & Corporate Services

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Communications

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Ian D. Hargrave
Vice President, Project Development

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Vice President, Risk & Pension

Robert C. Neumann
Vice President, Internal Audit

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Vice President, Corporate Secretary
& Administration

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Vice President, HR Services

Paul G. Wright
Vice President, Finance,
Controller & Treasurer

Carol Gear
Assistant Corporate Secretary

PRESIDENTS OF PRINCIPAL OPERATING SUBSIDIARIES

Richard (Rick) J. Brouwer
President, ATCO Power Ltd.

Kevin J. Cumming
President, ATCO Midstream Ltd.

Brian R. Hahn
President, ATCO Gas

Roberta (Bobbi) L. Lambright
President, ATCO I-Tek Inc.

Robert (Bob) J. Myles
President, ATCO Pipelines
President, ATCO Energy Solutions Ltd.

Settimio (Sett) F. Policicchio
President, ATCO Electric Ltd.

Joseph (Joe) J. Schnitzer
President, ASHCOR Technologies Ltd.

Peter N. Stratton
President, ATCO Travel Ltd.

Henry (Harry) G. Wilmot
President & Chief Operating Officer,
ATCO Frontec Corp.

Commitment to Environment
ATCO Environmental Stewardship 2008

ATCO Group is a diversified corporation with operations around the world.

The pursuit of operational excellence is core to how we do business and integral to the numerous steps we are taking to reduce our impact on the natural environment.

Operational excellence shapes the tools and measurements that help keep our customers and our people safe.

Our companies and their people are committed to addressing the challenges that affect communities touched by our businesses. ATCO is noted for its spirit of innovation, integrity and the sustainability of vibrant communities in which we operate.

We approach the mitigation of our environmental impact with the same discipline, strategies, accountability, and transparency that has been the foundation of our corporation's long-term success.

Some of our many initiatives, both big and small, are outlined in this pullout. Many more are envisaged as we work collaboratively with all our partners, including government, to maintain both a healthy environment and economy.

N.C. South

Nancy C. Southern
Deputy Chair, President & Chief Executive Officer

RECYCLED COMPUTER EQUIPMENT TURNS ELECTRONIC WASTE INTO LEARNING OPPORTUNITIES

ATCO I-Tek donated more than 1,600 pieces of computer equipment in 2008 to the Alberta Computers for Schools program. The initiative provides refurbished computers to Canadian schools, public libraries and non-profit learning organizations.

A supporter of this program since 2000, to date ATCO I-Tek has donated more than 9,250 pieces of equipment including desktop computers, laptops, monitors and printers. Through its commitment to this program, the company is investing in future generations while reducing the impact of electronic waste on the environment.

Students use donated refurbished electronic equipment from ATCO I-Tek to expand learning opportunities.

ASHCOR's fly ash storage tanks at Sheerness Generating Station near Hanna, Alberta.

ONE MILLION TONNES OF CARBON DIOXIDE EMISSIONS ELIMINATED BY ASHCOR

ASHCOR Technologies Ltd. celebrated its 10th anniversary in 2008 having surpassed the landmark of reducing carbon dioxide emissions by more than one million tonnes.

Part of ATCO's Power Generation Group, ASHCOR markets fly ash, the non-combustible portion of coal from ATCO Power's two thermal generating facilities.

Fly ash is a strategic construction material used as a partial replacement for Portland cement in concrete for homes, high-rise buildings, roads, dams and for oil and gas well cementing.

Over the past decade, ASHCOR has captured and re-used more than one million tonnes of waste by-product. In doing so, it has prevented more than one million tonnes of carbon dioxide from being released into the atmosphere. This has had the equivalent environmental impact of taking nearly a quarter million vehicles off the road for a full year.

ATCO MIDSTREAM REDUCES FLARING WITH THE FIRST PROJECT OF ITS KIND IN MANITOBA

ATCO Midstream and partner Stittco Energy Limited in 2008 officially opened a new 40-kilometre pipeline, which through collaboration with Canadian Natural Resources Ltd., eliminates about 18,500 tonnes of greenhouse gas emissions annually. This is achieved by reducing the flaring of solution gas associated with local oil production. The initiative is the only project of its kind in Manitoba.

The project transports otherwise flared solution gas from Canadian Natural's Pierson battery in southwest Manitoba where it connects to the Wolstitmor Gas Gathering System. The gas is transported through the gathering system to the Nottingham gas plant in southeastern Saskatchewan for the extraction of propane, butane and other useable products. The greenhouse gas reduction is equivalent to the amount generated during the heating of approximately 2,200 typical Canadian homes each year.

CANADIAN UTILITIES LIMITED

An ATCO Company

ATCO MAKES SENSE OF YOUR ENERGY USE

Walter Dunnewold of ATCO Gas and Lindsay Maundrell of ATCO EnergySense review company brochures listing energy saving tips for consumers.

From home renovation trade shows across the province to making presentations at public libraries, ATCO EnergySense professionals helped Albertans conserve energy in 2008.

ATCO EnergySense also conducted more than 1,900 in-depth assessments of homes and businesses, providing detailed recommendations on how people can save money and help the environment by efficiently managing energy use.

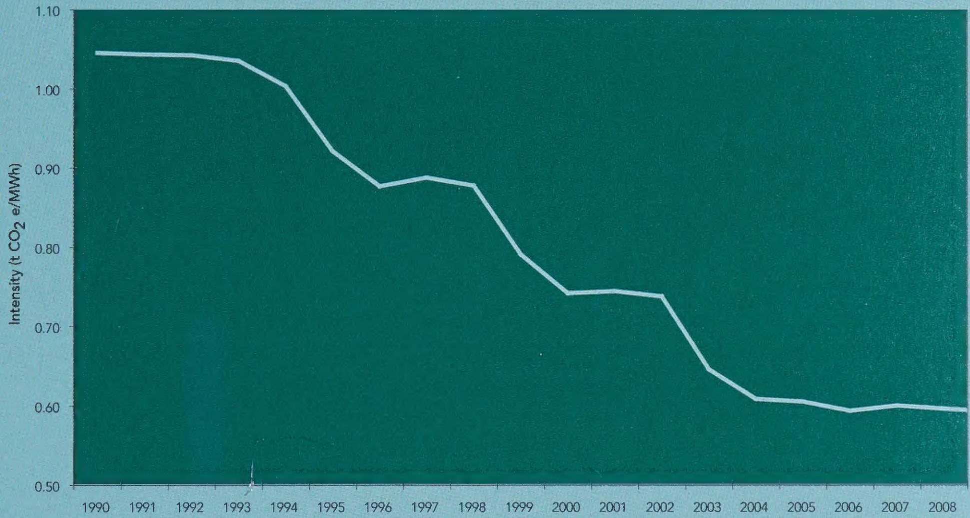
Since ATCO EnergySense was first formed in 2001, more than 135,000 requests for advice have been answered by email and telephone.

The ATCO EnergySense website is home to the ATCO EnergySense House, an easy-to-use tool that guides viewers through every room to show how energy is unnecessarily wasted and how it can be saved. It shows the real cost of using major appliances and equipment in people's homes.

ATCO Gas and ATCO Electric established the ATCO EnergySense program to provide Albertans with unbiased energy efficiency advice and services for their home or business. In addition to cost savings, the in-depth analysis of homes has resulted in the reduction of approximately 41,000 tonnes of greenhouse gas emissions annually.

Energy assessments on more than 400 commercial and industrial facilities have identified the potential for an additional reduction of more than 25,000 tonnes of greenhouse gas emissions.

ATCO POWER GLOBAL GREENHOUSE GAS (GHG) EMISSIONS INTENSITY



The graph portrays the GHG emissions intensity of ATCO Power's ownership interests in power plants around the globe. ATCO Power has substantially reduced its GHG intensity over the years by expanding its fleet with technologically advanced and environmentally progressive independent power plants. In addition, it has implemented new technologies in its thermal legacy plants.

ATCO POWER PIONEERS MERCURY CAPTURE TECHNOLOGY

In 2008, ATCO Power embarked on numerous initiatives to track and improve its environmental performance.

A large scale pioneering initiative to capture mercury using new technology was undertaken at ATCO Power's Battle River station in Alberta.

The Battle River project modelled an earlier 2006 test conducted at the Sheerness facility, where a portion of the exhaust was diverted through experimental mercury control equipment.

The long-term goal is to reduce mercury emissions by 70 per cent from existing coal-fired plants. ATCO Power is on track to meet obligations to comply with Alberta Government regulations regarding mercury capture by 2011.

ATCO Power also completed its first Corporate Sustainability Report and participated in completing ATCO Group's Carbon Disclosure Survey, an international effort to report on environmental progress.

The Battle River generating station, located approximately 200 kilometres southeast of Edmonton, was used to test advanced mercury capture technology as the facility seeks to reduce its environmental impact.

ATCO ELECTRIC EMISSIONS REDUCTIONS

ATCO Electric continuously looks for opportunities to improve efficiencies in its operations to reduce emissions. The table below provides the emissions reductions and emissions intensity reductions achieved (along with reduced net generation) between 2002 and 2008.

Isolated fossil fuel generation	2002	2008	
Net generation (GWh)	96.9	79.2	18.2% reduction
Total emissions (tonnes CO_2 equiv)	86,800	55,800	35.7% reduction
Emission intensity (tonnes CO_2/GWh)	896	705	21.3% reduction

ATCO ELECTRIC DEVELOPS LEADING-EDGE PLAN TO PROTECT BIRDS

In 2008, ATCO Electric completed its Avian Protection Plan. This plan takes a proactive approach to minimizing bird interaction with equipment and facilities, including collisions, electrocutions, nesting, and perching. ATCO Electric has been addressing avian-related issues on the transmission and distribution system for several years. The Avian Protection Plan consolidates and builds on these efforts in one comprehensive, company-wide plan aimed at reducing bird collisions and mortality, as well as facility outages and equipment damage.

Key plan elements include strategies for nest management, recommendations for incorporating safeguards in new facility design and construction, considerations for new line routing, measures to reduce bird mortality on existing poles, and a new reporting system to track incidents.

Phased implementation of the plan is expected to begin in 2009.

Wildlife protectors installed atop substation transformers significantly reduce potential bird electrocution at ATCO Electric facilities.

ATCO Gas natural gas vehicles are safe, economical, and reduce greenhouse gas emissions by up to 27 per cent when compared to conventional gasoline-powered vehicles.

FROM CARS TO HOMES: ATCO GAS IS IMPROVING THE ENVIRONMENT

Pursuing commercially viable alternative energy delivery is a goal of ATCO Gas. The company partnered to create a sustainable community in McKenzie Towne, southeast Calgary.

It began installing geothermal and solar energy technologies in homes, providing space heating, cooling and water heating. When the project is complete, ATCO Gas will own and maintain the alternative energy systems.

The company has also partnered in a leading-edge solar community called Drake's Landing in nearby Okotoks.

When fully operational, each of the project's 52 homes in Okotoks will reduce greenhouse gas emissions by 3.9 to five tonnes per year.

This year, ATCO Gas continued to convert vehicles in its fleet to burn natural gas. It has been adding six to eight natural gas vehicles to its fleet every year since the 1990's. In 2008, 10 vehicles were converted to run on natural gas.

A "Green-Breaking" ceremony in southeast Calgary celebrated a renewable energy pilot project, which will supply homes with space heating and cooling requirements as well as a portion of their hot water needs.

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